Gastar Exploration Inc.
Form 10-K
March 13, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013

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: 001-35211

GASTAR EXPLORATION INC.

(Exact name of registrant as specified in its charter)

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:

Title of each class	Name of exchange on which registered
Common Stock -- $0.001 par value per share	NYSE MKT LLC
8.625% Series A Cumulative Preferred Stock	NYSE MKT LLC
10.75% Series B Cumulative Preferred	NYSE MKT LLC

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity of Gastar Exploration Inc. held by non-affiliates of Gastar Exploration Inc. as of June 28, 2013 (the last business day of Gastar Exploration Inc.'s most recently completed second fiscal quarter) was approximately $157.1 million based on the closing price of $2.67 per share on the NYSE MKT LLC.

The total number of outstanding common shares, no par value per share, as of March 11, 2014 was 61,889,655.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

EXPLANATORY NOTE

On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation, changed its jurisdiction of incorporation to the State of Delaware and changed its name to “Gastar Exploration, Inc.,” which we refer to herein as “Parent.” On January 31, 2014, Parent merged with and into Gastar Exploration USA, Inc., its direct subsidiary, as part of a reorganization to eliminate Parent’s holding company corporate structure. Pursuant to the merger agreement, shares of Parent’s common stock were converted into an equal number of shares of common stock of Gastar Exploration USA, Inc. and Gastar Exploration USA, Inc. changed its name to “Gastar Exploration Inc.” (without the comma). Gastar Exploration Inc., together with its subsidiaries, owns and will continue to conduct Parent’s business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger. Shares of Gastar Exploration Inc.'s common stock are listed on the NYSE MKT LLC under the symbol “GST.” Shares of Gastar Exploration Inc.'s 8.625% Series A Cumulative Preferred Stock (symbol “GST.PRA”) and its 10.75% Series B Cumulative Preferred Stock (symbol “GST.PRB”) are also listed on the NYSE MKT LLC. As a result of the merger, Gastar Exploration, Inc.’s reporting obligations under the Exchange Act were terminated.

This Annual Report on Form 10-K (the “Form 10-K”) is filed by Gastar Exploration Inc. As a result of the merger described above, Gastar Exploration Inc. is the successor issuer to Parent pursuant to Rule 12g-3 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Pursuant to Rule 12g-3(g) under the Exchange Act, this Form 10-K contains information that would be required if filed by Parent, as the predecessor.

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GASTAR EXPLORATION INC. AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2013
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K and the documents incorporated herein contain “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 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,” “anticipate,” “believe,” “estima “potential,” “pursue,” “target” or “continue,” the negative of such terms or variations thereon, or 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;
- oil, natural gas and natural gas liquids (“NGLs”) reserves;
- timing and amount of future production of oil, condensate, natural gas 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:

- our ability to successfully integrate acquired assets with ours and realize the anticipated benefits from such acquisitions;
- the supply and demand for oil, condensate, natural gas and NGLs;
- low and/or declining prices for oil, condensate, natural gas and NGLs;
- price volatility of oil, condensate, natural gas and NGLs;
- worldwide political and economic conditions and conditions in the energy market;
- our ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or 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 oil and natural gas properties;
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uncertainties about the estimated quantities of oil and natural gas reserves and in the projection of future rates of production and timing of development expenditures of proved reserves;

- strength and financial resources of competitors;

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- availability and cost of material and equipment, such as drilling rigs and transportation pipelines;
- availability and cost of processing and transportation;
- changes or advances in technology;
- 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;
- our 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) for any date or period prior to January 31, 2014,“Gastar,” the “Company,” “we,” “us,” “our” and similar terms refer collectively to Gastar Exploration, Inc.(formerly known as Gastar Exploration Ltd.) and its subsidiaries, including Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.), and for any date or period after January 31, 2014, such terms refer collectively to Gastar Exploration Inc. and its subsidiaries, (ii) “Gastar USA” refers to Gastar Exploration USA, Inc., which until January 31, 2014 was a first-tier subsidiary of Gastar Exploration, Inc. and primary operating company as of December 31, 2013, (iii) “Parent” refers to Gastar Exploration, Inc., (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”). On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar USA as part of a reorganization to eliminate the holding company corporate structure of Parent. Pursuant to the merger agreement, shares of Parent’s common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to “Gastar Exploration Inc.” Gastar Exploration Inc., together with its subsidiaries, owns and will continue to conduct Gastar’s business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger.

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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
Boe	One barrel of oil 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
CRP	Central receipt point
FASB	Financial Accounting Standards Board
GAAP	Accounting principles generally accepted in the United States of America
Gross acres	Refers to acres in which we own a working interest
Gross wells	Refers to wells in which we have a working interest
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condensate or NGLs per day
MBoe	One thousand barrels of oil equivalent
MBoe/d	One thousand barrels of oil equivalent 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
Net acres	Refers to our proportionate interest in acreage resulting from our ownership in gross acreage
Net wells	Refers to gross wells multiplied by our working interest in such wells
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 oil, condensate, natural gas and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. We are currently pursuing development within the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play in Oklahoma and the development of liquids-rich natural gas in the Marcellus Shale play in West Virginia. We also hold prospective Utica Shale acreage in West Virginia and prospective Marcellus Shale acreage in Pennsylvania. We completed the sale of substantially all of our East Texas assets on October 2, 2013, with an effective date of January 1, 2013.

On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation, changed its jurisdiction of incorporation to the State of Delaware and changed its name to “Gastar Exploration, Inc.” On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar USA as part of a reorganization to eliminate the holding company corporate structure of Parent. Pursuant to the merger agreement, shares of Parent’s common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to “Gastar Exploration Inc.” Gastar Exploration Inc., together with its subsidiaries, owns and will continue to conduct our business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger. Shares of Gastar Exploration Inc.'s common stock are listed on the NYSE MKT LLC under the symbol “GST.” Shares of Gastar Exploration Inc.'s 8.625% Series A Cumulative Preferred Stock (symbol “GST.PRA”) and its 10.75% Series B Cumulative Preferred Stock (symbol “GST.PRB”) are also listed on the NYSE MKT LLC. 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:

- exploitation and development of our Mid-Continent assets in the Hunton Limestone horizontal oil play;
- continued exploitation of existing Marcellus Shale West Virginia assets with a focus on areas that we believe are prospective for natural gas with relatively high condensate and NGLs content;
- initial testing of the Utica Shale in an area believed to be prospective for high deliverable dry gas volumes;
- active management of our domestic drilling programs; and
- effective management and utilization of technological expertise.

Exploitation and Development in the Hunton Limestone Horizontal Oil Play

During 2012, we began acquiring leasehold in an emerging oil play located in Oklahoma. We continued to build our acreage position in this region during 2013 in partnership with our operating partner in the initial AMI prospect area and two additional adjacent prospect areas. We also increased exposure to the play through acquisitions of acreage and producing wells from Chesapeake Exploration, L.L.C. and Jamestown Resources, L.L.C. (the “Chesapeake Parties”) and Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. (the “Lime Rock Parties”), respectively. Our Mid-Continent development 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 with conventional completion techniques. We, along with our operating partner in the initial AMI, drilled and completed one gross (0.5 net) horizontal non-operated well during 2012 and drilled and completed six gross (3.0 net) horizontal non-operated wells during 2013 on our Mid-Continent properties. Additionally, during 2013, we drilled and completed our first two gross (1.8 net) operated wells in the lower Hunton Limestone. To continue testing the potential of the formation, we have also participated in three gross (0.9 net) wells outside of our AMI acreage targeting the Hunton Limestone, the Woodford Shale and the Mississippi Lime. We will focus the majority of our 2014 capital budget on drilling existing leasehold, leasehold renewal and leasehold acquisition in the Hunton Limestone horizontal oil play, with approximately 59% of our 2014 capital budget allocated to developing our Hunton Limestone properties. Our 2014 capital budget includes plans to spud a total of 36 gross (17.1 net) wells, comprised of 27 gross (9.7 net) non-operated wells primarily located within our current AMI and 9 gross (7.4 net) operated wells, including two gross (2.0 net) wells in the West Edmond Hunton Lime Unit ("WEHLU"). We anticipate completing 35 gross wells in the Hunton Limestone during 2014.

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Continue Exploitation of Existing Marcellus Shale Assets and Focus on Areas with Relatively High NGLs and Condensate Content along with Initial Testing of High Rate Dry Gas Potential in the Utica Shale.

We are continuing to focus our drilling activity in the liquids-rich area of the Marcellus Shale and have allocated approximately 35% of our 2014 capital budget to the Marcellus Shale. In April 2014, we will commence exploration in the Utica Shale in West Virginia. Our 2014 capital budget includes plans to spud a total of 11 gross (5.5 net) operated wells in these areas, including 10 gross Marcellus Shale wells and one gross Utica Shale well. We anticipate completing 14 gross (7.0 net) wells in the Marcellus Shale and Utica Shale in 2014, which includes three gross (1.5 net) Marcellus Shale wells that were drilled but not completed in 2013. Our Utica Shale well test is planned to spud in April 2014 and should be completed by third quarter 2014. We believe that the continued expansion of our acreage position and our drilling activity in the Marcellus Shale during 2013 has provided us with a multi-year inventory of drilling opportunities. Our focus continues to be within the liquids-rich area of the Marcellus Shale with subsequent focus on drilling acreage in order to hold the acreage “by production” prior to lease term expirations. We anticipate that our Utica Shale production will be dry gas, but has the potential to yield high natural gas delivery rates at levels that may generate attractive internal rates of return despite the absence of liquids.

Actively Manage Our Domestic Drilling Program

We believe that operating approximately 76% of our drilling projects for 2014 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, Utica Shale and Hunton Limestone wells.

Manage and Utilize Technological Expertise

We believe that 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.

Oil and Natural Gas Activities

The following provides an overview of our major oil and natural gas projects during 2013. 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. For additional information regarding our historical research and development expenditures, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operation.”

Mid-Continent Horizontal Oil Play

The Hunton Limestone is a limestone formation stretching for over 2.7 million acres mainly in Oklahoma, but also in the neighboring states of Texas, New Mexico and Arkansas. Hunton Limestone economics are attractive due to the high quality oil production and the associated production of high BTU content natural gas in the area. As of December 31, 2013, we held leases covering approximately 209,100 gross (126,000 net) acres in Major, Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the Hunton Limestone horizontal oil play. Our leasing activities in the initial AMI prospect area, primarily located in northwest Kingfisher County, Oklahoma, began in 2012 and have been expanded to include two additional adjacent prospect areas. 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 the initial 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 the initial 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%). In all subsequent prospect areas, we pay 54.25% of gross drilling and completion costs to earn a 50% working interest. Our AMI partner handles all drilling, completion and production activities, and we handle all leasing and permitting activities in the initial AMI. We expect to continue to build our acreage position in this region during 2014, both inside and outside of the AMI.

On November 15, 2013, we acquired a 98.3% working interest (80.5% net revenue interest) in 24,000 net acres of oil and natural gas leasehold interests in the West Edmond Hunton Lime Unit located in Kingfisher, Logan and Oklahoma Counties, Oklahoma, including production from interests in 56 gross (55.0 net) producing wells, for an adjusted cash purchase price of approximately $177.8 million (reflecting adjustment for an acquisition effective date of August 1, 2013.

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As of December 31, 2013 and currently as of the date of this report, we had production and drilling operations at various stages on the following wells in our original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Initial Production Rate (Boe/d)	Cumulative Production[1](MBoe)	EUR[2] (MBoe)	Oil EUR %	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Mid-Con 1H[3]	50.0%	4,200	112	23.6	48.8	71%	October 5,2012	$5.0
Mid-Con 2H	50.0%	4,100	1,383	248.6	852.1	59%	February 15, 2013	$5.3
Mid-Con 3H[4]	70.9%	4,300	111	16.3	54.8	95%	April 4, 2013	$5.1
Mid-Con 4H	50.0%	4,200	176	17.5	100.5	59%	April 24, 2013	$4.8
Mid-Con 5H	50.0%	4,600	390	38.0	425.8	69%	August 23, 2013	$6.4
Mid-Con 6H [5]	50.0%	4,100	1,442	138.1	1,035.2	64%	October 6, 2013	$5.7
Mid-Con 7H [6]	47.5%	4,100	906	46.3	387.3	63%	November 15, 2013	$5.2
Mid-Con 8H	54.9%	3,900	N/A	N/A	N/A	N/A	Flowback commenced on February 1, 2014	$5.3
Mid-Con 9H	47.4%	4,400	N/A	N/A	N/A	N/A	Completion operations in progress	N/A
Mid-Con 10H	48.4%	4,200	N/A	N/A	N/A	N/A	Completion operations in progress	N/A
Mid-Con 11H	30.2%	4,300	N/A	N/A	N/A	N/A	Awaiting completion	N/A
Mid-Con 12H	49.3%	4,400	N/A	N/A	N/A	N/A	Drilling	N/A
Mid-Con 13H	23.6%	4,400	N/A	N/A	N/A	N/A	Drilling	N/A

(1) Cumulative production through February 28, 2014.
(2) Estimated ultimate recovery of proved reserves (prior production plus estimated remaining proved reserves) based on Wright & Company, Inc.'s December 31, 2013 SEC report.
(3) Upper Hunton well completion.
(4) After payout working interest is 56.7%.
(5) Well estimated to be producing from 8 of 20 frac stages at this time due to down-hole mechanical issues.
(6) Well flowing cumulative production 45.6 MBoe. Well placed on gas lift on February 22, 2014.

We continue to target our horizontal laterals in the lower Hunton Limestone formation and increase the number of fracs in the horizontal lateral as warranted by log analysis. We are continuing to monitor well flow back results on recently drilled and completed wells and remain encouraged by the high volumes of completion fluids being flowed back and higher oil production percentage.

On June 7, 2013, we acquired approximately 157,000 net acres of oil and natural gas leasehold interests in Canadian and Kingfisher Counties, Oklahoma from the Chesapeake Parties, including production interests in 206 producing wells for an adjusted cash purchase price of approximately $69.4 million (reflecting adjustment for an acquisition effective date of October 1, 2012). The asset purchase agreement contains customary representations, warranties and covenants, including provisions for indemnification, subject to certain limitations described therein. Effective July 1, 2013, our working interest partner in its original AMI in Oklahoma exercised its rights to acquire approximately 12,800 net acres and certain proved properties that we acquired from the Chesapeake Parties for a total payment of $11.6 million (reflecting adjustment for an acquisition effective

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date of October 1, 2012). In addition, on August 6, 2013, we sold approximately 76,000 net acres in Kingfisher and Canadian Counties, Oklahoma to Newfield Exploration Mid-Continent Inc. ("Newfield") for an adjusted purchase price of approximately $57.0 million cash net of our purchase of approximately 1,850 net acres of Oklahoma oil and gas leasehold interests from Newfield for $1.5 million.

As of December 31, 2013 and currently as of the date of this report, we had production and drilling operations at various stages on the following operated wells on our acquired acreage in the Hunton Limestone formation:

				Initial Production Rates [1]				
Well Name	Current Working Interest	Current Approximate Net Revenue Interest	Approximate Lateral Length (in feet)	Oil (Bbl/d)	Natural Gas (Mcf/d)	BOE/d	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Burton 16-1H	79.0%	81.0%	4,100	72	235	111	December 7, 2013	$7.4
Townsend 6-1H	100.0%	80.0%	3,700	144	440	217	January 10, 2014	$6.7
Taborek 22-1H	87.4%	68.6%	3,000	N/A	N/A	N/A	Completion operations in progress	$7.9

(1) Represents highest daily gross oil peak rate to date and associated gas rate.

We have also participated in 3.0 gross (0.9 net) wells outside of our AMI acreage targeting the Hunton Limestone, the Woodford Shale and the Mississippi Lime formations.

At December 31, 2013, proved reserves attributable to the Mid-Continent were approximately 106.4 Bcfe (17.7 MMBoe), a 100% increase from year-end 2012 reserves. As of December 31, 2013, Mid-Continent proved reserves represented approximately 32% of our total proved reserves. Total Mid-Continent proved reserves at year-end 2013 were comprised of approximately 68% of oil and condensate and NGLs reserves. Approximately 51% of the Mid-Continent year-end 2013 reserves are proved developed.

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The following table provides production and operational information about the Mid-Continent for the periods indicated:

	For the Years Ended December 31,		
Mid-Continent	2013	2012	2011
Production:			
Natural gas (MMcf)	1,095	1	—
Oil and condensate (MBbl)	189	2	—
NGLs (MBbl)	23	—	—
Total production (MMcfe)	2,371	11	—
Total Production (MBoe)	395	2	—
Natural gas (MMcf/d)	3.0	—	—
Oil and condensate (MBbl/d)	0.5	—	—
NGLs (MBbl/d)	0.1	—	—
Total daily production (MMcfe/d)	6.5	0.03	—
Total daily production (MBoe/d)	1.1	0.01	—
Average sales price per unit (1):			
Natural gas (per Mcf)	$4.75	$3.47	$—
Oil and condensate (per Bbl)	$94.80	$85.22	$—
NGLs (per Bbl)	$33.06	$36.15	$—
Average sales price per Mcfe (1)	$10.09	$12.60	$—
Average sales price per Boe (1)	$60.53	$75.58	$—
Selected operating expenses (in thousands):			
Production taxes	$820	$2	$—
Lease operating expenses	$4,019	$33	$—
Transportation, treating and gathering	$3	$—	$—
Selected operating expenses per Mcfe:			
Production taxes	$0.35	$0.20	$—
Lease operating expenses	$1.69	$3.13	$—
Transportation, treating and gathering	$—	$—	$—
Production costs (2)	$1.70	$3.13	$—
Selected operating expenses per Boe:			
Production taxes	$2.08	$1.22	$—
Lease operating expenses	$10.17	$18.79	$—
Transportation, treating and gathering	$0.01	$—	$—
Production costs (2)	$10.17	$18.79	$—

(1) Excludes the impact of hedging activities.
(2) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

For the three months ended December 31, 2013, net production from the Mid-Continent averaged 14.1 MMcfe/d (2.3 MBoe/d) compared to 7.0 MMcfe/d (1.2 MBoe/d) for the three months ended September 30, 2013 and 0.1 MMcfe/d (0.02 MBoe/d) for the three months ended December 31, 2012.

For the fiscal year 2014, in the Mid-Continent, we currently anticipate that we will spud a total of 36 gross (17.1 net) wells comprised of 27 gross (9.7 net) non-operated wells primarily located within our original AMI and 9 gross (7.4 net) operated wells, including two gross (2.0 net) within our WEHLU acreage. We anticipate completing 35 gross (16.9 net) Oklahoma wells during 2014.

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Marcellus Shale

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 hydraulic fracture stimulation have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of December 31, 2013, our acreage position in the play was approximately 81,900 gross (59,900 net) acres. We refer to the approximately 31,200 gross (13,100 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to our joint venture (the “Atinum Joint Venture”) with an affiliate of Atinum Partners Co. Ltd. (“Atinum”) as our “Marcellus West acreage.” We refer to the approximately 50,800 gross (46,800 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. We continue to opportunistically swap acreage with adjacent operators in order to optimize our acreage and maximize horizontal lateral lengths.

On September 21, 2010, we entered into the Atinum Joint Venture pursuant to which 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 at that date, 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”). In early 2012, we made additional assignments to Atinum as a result of which Atinum now owns a 50% interest in the Atinum Joint Venture Assets. 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 are the operator and are obligated to offer any future lease acquisitions to Atinum on a 50/50 basis. Atinum will pay us on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs, up to $20.0 million, and 5% of such costs on activities above $20.0 million.

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, we and Atinum agreed during the first quarter of 2012 to reduce the 2012 minimum wells to be drilled requirement from 24 wells to 20 wells. We and Atinum 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. Additionally, we and Atinum agreed to reduce the 2013 minimum wells to 19 gross wells, resulting in 57 gross (27.0 net) wells on production at December 31, 2013, compared to the 60 gross wells originally agreed upon. All of our Marcellus Shale well operations to date were under the Atinum Joint Venture.

As of December 31, 2013, and currently as of the date of this report, we had drilling operations at various stages on the following Marcellus Shale 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
Goudy(2)	3.0	1.5	50.0%	40.5%	6,100	Waiting on completion	Second Quarter 2014
Armstrong	9.0	4.5	50.0%	40.5%	5,000	Top holes completed	Third Quarter 2014
Hansen	5.0	2.5	50.0%	40.5%		Top holes in progress	Fourth Quarter 2014
	17.0	8.5					

(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) The Goudy pad will ultimately have nine wells, four of which were placed on production in August 2013 and three of which are scheduled to be on production in the second quarter of 2014.

As of December 31, 2013, we had in interest in seven gross (1.3 net) non-operated horizontal Marcellus Shale wells in Butler County, Pennsylvania and an additional four gross (0.9 net) non-operated horizontal Marcellus Shale wells in Marshall County, West Virginia. Currently, we have no plans to participate in any additional Marcellus Shale non-operated wells in 2014.

For the year ended December 31, 2013, net production from the Marcellus Shale averaged 39.2 MMcfe/d (6.5 MBoe/d) compared to 22.0 MMcfe/d (3.7 MBoe/d) in 2012. For the three months ended December 31, 2013, net production from the Marcellus Shale averaged 41.0 MMcfe/d (6.8 MBoe/d) compared to 43.0 MMcfe/d (7.2 MBoe/d) for the three months ended September 30, 2013 and 29.9 MMcfe/d (5.0 MBoe/d) for the three months ended December 31, 2012. Since the inception of our operations in the Marcellus Shale in 2011, our operated production and sales in West Virginia were 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 continually taken steps to attempt to resolve these issues. In May 2012, dehydration capacity was increased from 40 MMcf/d to 70 MMcf/d and compression was added to reduce line pressure to approximately 550 psi at the Corley CRP. In late March 2013, a second CRP was added at our Burch Ridge pad with additional dehydration capacity, bringing total dehydration capacity for our natural gas production to approximately 140 MMcf/d. In mid-April 2013, compression was added at the Burch Ridge CRP to reduce line pressures to approximately 550 psi. For the year ended December 31, 2013, we estimate that third-party gathering system downtime and high line pressure resulted in reduced production of approximately 6.8 MMcfe/d (1.1 MBoe/d), or 13% of total production, compared to 1.8 MMcfe/d (0.3 MBoe/d), or 5%, of total 2012 production. Since October 1, 2013, we have not experienced significant curtailment or high line pressure issues on our Marcellus West production on the third-party gathering system. On July 16, 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs. On December 31, 2013, the parties informed the Arbitration Panel that they had reached an agreement in principle to settle their disputes. The settlement is subject to final documentation, which has not yet been completed. At the request of both parties, on January 9, 2014, the Arbitration Panel stayed all proceedings, pending completion of the final settlement documentation. See “Financial Statements, Note 14, “Commitments and Contingencies” of this Form 10-K.

At December 31, 2013, proved reserves attributable to the Marcellus Shale were approximately 221.4 Bcfe (36.9 MMBoe), a 45% increase from year-end 2012 reserves of 153.2 Bcfe. As of December 31, 2013, Marcellus Shale proved reserves represented approximately 68% of our total proved reserves compared to 85% of total proved reserves at December 31, 2012. Total Marcellus Shale proved reserves at year-end 2013 were comprised of approximately 34% of condensate and oil and NGLs reserves compared to 32% at year-end 2012. Approximately 58% of the Marcellus Shale year-end 2013 reserves are proved developed compared to 65% at December 31, 2012.

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

	For the Years Ended December 31,		
Marcellus Shale	2013	2012	2011
Production:			
Natural gas (MMcf)	9,594	5,477	672
Oil and condensate (MBbl)	315	160	11
NGLs (MBbl)	471	270	21
Total production (MMcfe)	14,309	8,058	860
Total production (MBoe)	2,385	1,343	143
Natural gas (MMcf/d)	26.3	15.0	1.8
Oil and condensate (MBbl/d)	0.9	0.4	—
NGLs (MBbl/d)	1.3	0.7	0.1
Total daily production (MMcfe/d)	39.2	22.0	2.4
Total daily production (MBoe/d)	6.5	3.7	0.4
Average sales price per unit (1):			
Natural gas (per Mcf)	$2.86	$2.33	$3.43
Oil and condensate (per Bbl)	$55.61	$62.40	$71.37
NGLs (per Bbl)	$31.52	$28.22	$52.47
Average sales price per Mcfe (1)	$4.18	$3.77	$4.82
Average sales price per Boe (1)	$25.08	$22.62	$28.92
Selected operating expenses (in thousands):			
Production taxes	$3,805	$2,138	$272
Lease operating expenses	$3,181	$2,070	$832
Transportation, treating and gathering	$1,176	$1,090	$85
Selected operating expenses per Mcfe:			
Production taxes	$0.27	$0.27	$0.32
Lease operating expenses	$0.22	$0.26	$0.97
Transportation, treating and gathering	$0.08	$0.14	$0.10
Production costs (2)	$0.29	$0.38	$1.03
Selected operating expenses per Boe:			
Production taxes	$1.60	$1.59	$1.89
Lease operating expenses	$1.33	$1.54	$5.80
Transportation, treating and gathering	$0.49	$0.81	$0.59
Production costs (2)	$1.76	$2.29	$6.26

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(1) Excludes the impact of 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 2014, we plan to spud a total of 11 gross (5.5 net) operated wells, including 10 gross Marcellus Shale wells in Marshall County, West Virginia. We anticipate completing 14 gross (7.0 net) wells, which includes 3 gross (1.5 net) wells that were drilled but not completed in 2013.

Utica Shale

The Utica Shale is Ordovician aged shale that underlies much of the Appalachian region of Pennsylvania, Ohio and West Virginia. The depth of the Utica Shale and its low permeability make the Utica Shale an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and hydraulic fracture stimulation have produced promising results in the Utica Shale, some in close proximity to our existing Marcellus West acreage. Based on log analysis of offsetting

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wells and recent Utica Shale completions by other nearby operators, we believe that our Marcellus West acreage could be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale.
For fiscal year 2014, we plan to drill and complete one gross (0.5 net) Utica Shale well. Our operated Utica Shale well test is estimated to spud in April 2014 and should be completed during the third quarter of 2014.
Hilltop Area, East Texas
On October 2, 2013, we sold substantially all of our leasehold interests in the Hilltop Area of East Texas, consisting of 31,800 gross (16,300 net) acres and 37 producing wells to Cubic Energy, Inc. for net proceeds of approximately $42.9 million (reflecting adjustments for an accounting effective date of January 1, 2013 and other customary adjustments). For the year ended December 31, 2013, net production from the Hilltop area averaged 7.5 MMcfe/d (1.2 MBoe/d) compared to 13.7 MMcfe/d (2.3 MBoe/d) for the year ended December 31, 2012. The decrease in production primarily resulted from the sale of the properties on October 2, 2013.
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	2013 (3)	2012	2011
Production:			
Natural gas (MMcf)	2,661	4,914	6,127
Oil and condendsate (MBbl)	10	15	30
Total production (MMcfe)	2,722	5,005	6,304
Total production (MBoe)	454	834	1,051
Natural gas (MMcf/d)	7.3	13.4	16.8
Oil and condensate (MBbl/d)	—	—	0.1
Total daily production (MMcfe/d)	7.5	13.7	17.3
Total daily production (MBoe/d)	1.2	2.3	2.9
Average sales price per unit (1):			
Natural gas (per Mcf)	$2.90	$2.06	$3.17
Oil and condensate (per Bbl)	$99.64	$95.71	$90.12
Average sales price per Mcfe (1)	$3.20	$2.31	$3.51
Average sales price per Boe (1)	$19.22	$13.85	$21.03
Selected operating expenses (in thousands):			
Production taxes	$25	$84	$153
Lease operating expenses	$2,253	$3,624	$5,863
Transportation, treating and gathering	$2,822	$3,746	$3,962
Selected operating expenses per Mcfe:			
Production taxes	$0.01	$0.02	$0.02
Lease operating expenses	$0.83	$0.72	$0.93
Transportation, treating and gathering	$1.04	$0.75	$0.63
Production costs (2)	$1.79	$1.39	$1.45
Selected operating expenses per Boe:			
Production taxes	$0.06	$0.10	$0.15
Lease operating expenses	$4.97	$4.35	$5.58
Transportation, treating and gathering	$6.22	$4.49	$3.77
Production costs (2)	$10.74	$8.32	$8.71

(1) Excludes the impact of hedging activities.
(2) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

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(3) Includes production and cost information for the period January 1, 2013 to October 2, 2013 (the date of the sale). Per day production averages based on 365 days.

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 oil, condensate, natural gas and NGLs. The markets for oil, condensate, natural gas and NGLs have historically been and currently continue to be volatile. Oil, condensate, natural gas 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. We are directly impacted by natural gas prices in the regions in which we operate 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 near our Marcellus West and Marcellus East acreage in the Appalachian Basin. 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 sale of substantially all of our interest in East Texas, ETC Texas Pipeline, Ltd. (“ETC”) provided for the treating, purchase and transportation of substantially all of our natural gas production from this area. Our deep Bossier production was transported to the Katy Hub in Katy, Texas, where numerous parties were available to purchase our natural gas production. 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, condensate and NGLs production in the Appalachian Basin and the Mid-Continent is sold under spot sales transactions at market prices. Prior to the sale of our East Texas interests, our oil and condensate production in this region was 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 Marcellus West 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 520.0 MMcf/d 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. Since the inception of our operations in the Marcellus Shale in 2011, 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 continually taken steps to attempt to resolve these issues. In May 2012, dehydration capacity was increased from 40 MMcf/d to 70 MMcf/d and compression was added to reduce line pressure to approximately 550 psi at the Corley

CRP. In late March 2013, a second CRP was added at our Burch Ridge pad with additional dehydration capacity, bringing total dehydration capacity for our natural gas production to approximately 140 MMcf/d. In mid-April 2013, compression was added at the Burch Ridge CRP to reduce line pressures to approximately 550 psi. We are continuing to work with the third-party gathering system operator to resolve mid-stream downtime issues on our operated Marcellus Shale wells. Currently, we are experiencing no significant curtailment or high line pressure issues on our Marcellus West production on the third-party gathering system. On July 16, 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs as provided in the agreements. On December 31, 2013, the parties informed the Arbitration Panel that they have reached an agreement in

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principle to settle their disputes. The settlement is subject to final documentation, which has not yet been completed. At the request of both parties, on January 9, 2014, the Arbitration Panel stayed all proceedings, pending completion of the final settlement documentation. See "Financial Statements, Note 14, "Commitments and Contingencies" of this report.

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 covered delivery of our gross production of natural gas in the Hilltop area of East Texas to certain delivery points provided under the ETC Contract.The Hilltop Gathering Agreement provided for a minimum quarterly gathering gross production volume of 50.0 MMcf/d (35.0 MMcf/d 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 was less than the minimum quarterly requirement, the gathering fee was payable on such deficit. If excess quarterly production existed, such excess was carried forward to offset any future deficit quarters. The gathering fee on the initial gross 25 Bcf of production was $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reached 300 Bcf. As a condition to the sale of our East Texas interests, Cubic Energy assumed any future minimum volume requirement obligations.

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 had a term of 10 years. As a condition to the sale of our East Texas interests, Cubic Energy assumed the ETC Contract.

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

	For the Years Ended December 31,					
	2013		2012		2011	
SEI	56	%	47	%	8	%
Sunoco	16	%	—	%	—	%
Clearfield Appalachian	8	%	14	%	—	%
ETC	8	%	24	%	69	%
Plains Marketing LP	1	%	2	%	10	%

SEI and Clearfield Appalachian purchase the majority of our Marcellus Shale production. There are limited oil, condensate, natural gas and NGLs purchase and transportation alternatives currently available in the Appalachian Basin. If SEI or Clearfield Appalachian were to cease purchasing and transporting our oil, condensate, natural gas and NGLs production and we were 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, our ability to conduct normal operations would be significantly restricted. SEI and Sunoco purchase the majority of our Mid-Continent production. There are numerous purchase and transportation alternatives currently available in the Mid-Continent so in the event that SEI or Sunoco were to cease purchasing and transporting our oil, condensate, natural gas and NGLS production, our ability to conduct normal operations would not be significantly restricted. Prior to the sale of our East Texas interests, ETC treated, transported and purchased substantially all of our East Texas natural gas production and Plains Marketing LP purchased substantially all of our East Texas oil production. See "Item 1A. Risk Factors - Our ability to market our oil, condensate, natural gas and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our oil, condensate, natural gas 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 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 oil and natural gas 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 oil, condensate, natural gas and NGLs 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 oil and natural gas 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.

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

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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 worker 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 the Interior, the Occupational Safety and Health Administration and 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. The trend in environmental legislation and regulation is toward stricter standards to place more restrictions and limitations on activities that may affect the environment. 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, but there is no assurance that costs to

comply with existing and any new environmental laws and regulations in the future will not be material. 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 properties 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 Resource Conservation and Recovery Act, as amended (“RCRA”), and comparable state laws regulate the management, treatment, storage and disposal of hazardous and non-hazardous 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 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 and Subsurface Injections

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"), and analogous state laws. These laws and their implementing regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including oil and hazardous substances, into waters of the United States and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure ("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. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Depending on our area of operation, regional, state or local regulatory authorities typically govern the withdrawal of water for use in our operations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended ("OPA"), amends the CWA and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. 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 United States.

Our natural gas and oil exploration and production operations, and other operations in which we own an interest, generate produced water, drilling muds and other waste streams, some of which may be disposed by injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the Safe Drinking Water Act, as amended ("SDWA"), and analogous state laws. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected, and prohibits the migration of fluids containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages and personal injuries. While we believe that we have obtained the necessary permits from the applicable regulatory agencies for our underground injection wells and that we are in substantial compliance with permit conditions and federal and state rules, 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 would ultimately increase the cost of our operations, which costs could be significant. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continued production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

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 final permitting guidance in February 2014 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 in the semi-annual Regulatory Agenda published in July 2013, the agency continues to project the issuance of 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 draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Moreover, the

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EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards in 2014. Also, in May 2013, the Federal Bureau of Land Management ("BLM")published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. These 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, in 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. 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 and from pneumatic controllers and storage vessels. While we have not experienced any material adverse impact from complying with this rule, future compliance with these requirements could significantly increase our costs of development and production.

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 that exceed GHG emission thresholds. 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,

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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. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. 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 the listing of numerous 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 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 2014. 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. Permit authorizations under NEPA are subject to protests, appeal or litigation, any or all of which may also delay or halt projects. Moreover, 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.

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Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. For additional information relating to our disclosure of revenues, profits and total assets in the segment in which we operate, please see Item 8. ‘‘Financial Statements and Supplementary Data” included in this Form 10-K.

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 the 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 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 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. “Risk Factors. - The process of drilling for and producing oil and natural gas 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 11, 2014, we had 63 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 and 7,002 square feet of office space in Oklahoma City, Oklahoma.

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

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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 Conduct and Ethics;
- Corporate Governance Guidelines;
- Audit Committee Charter;
- Nominating and Governance Committee Charter:
- Compensation Committee Charter;
- Reserves Review Committee Charter; and
- 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 natural 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.

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 and recognition of a $27.7 million non-cash gain on acquisition of assets at fair value for the Chesapeake acquisition, and subsequent sale of certain properties acquired from Chesapeake, which resulted in net income of $40.0 million in 2013, we have not been profitable since we started our business. We incurred net losses of $160.9 million and $1.8 million for the years ended December 31, 2012 and 2011, respectively. Our capital has been employed in an increasingly expanding oil and natural gas exploration and development program, with our focus on finding significant oil and natural gas 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.

Oil, condensate, natural gas and NGLs prices are volatile and further declines 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 oil, condensate, natural gas and NGLs. Oil and natural gas 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 excluding the impact of hedging from 2011 to 2012 and a 12% increase in our realized NGLs prices per barrel excluding the impact of hedging from 2012 to 2013. Lower prices also may reduce the amount of oil, condensate, natural gas or NGLs that we can produce economically. Prices for oil, condensate, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil, condensate, natural gas 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;

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- 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;
- 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 oil, condensate, natural gas and NGLs prices in the specific areas where we operate, and these prices may be lower than prices at major markets.

Regional oil, condensate, natural gas 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 2013, approximately 20% of our natural gas production was priced based on the Katy Hub basis point and 72% was priced based on the Columbia Gas Appalachia Pool. Our West Virginia natural gas production is priced using the Columbia Gas Appalachia Pool. At December 31, 2013, the Henry Hub price was $4.42 per MMBtu, compared to our key basis point pricing of $4.34 per MMBtu at the Katy Hub and $4.24 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 2013, approximately 37% and 61% of our oil and condensate production was produced in the Mid-Continent and the Marcellus Shale, respectively, where we realized an average price per barrel of $94.80 and $55.61, respectively, excluding the impact of hedging activities for the year. This compares to the daily average WTI posted price of $94.49 per barrel for 2013. For the year ended December 31, 2013, our realized NGLs prices for Marcellus Shale and Mid-Continent NGLs production represented approximately 34% and 35%, respectively, of the full year 2013 daily unweighted average WTI posted price of $94.01.

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 oil and natural gas 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 oil and natural gas reserves. These expenditures will reduce the amount of cash available for distribution to our preferred stockholders and to service our indebtedness. Our capital budget for 2014 totals $191.8 million, and we expect to fund these expenditures using existing cash balances, cash generated internally from our operations, borrowings under our revolving credit facility, the possible divestiture of assets and the possible issuance of debt or 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 oil and natural gas reserves;
- The amount of oil, condensate, natural gas and NGLs that we produce from existing wells;
- The prices at which we sell our production;

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- The costs of developing and producing our oil and natural gas 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 oil or natural gas 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 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 and to service our indebtedness. 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 and to service our indebtedness. 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.

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

We have entered into New York Mercantile Exchange (“NYMEX”) futures contracts as hedges on approximately 12.0 Bcf of natural gas production and 934,000 Bbls of crude production in 2014, 2.8 Bcf of natural gas production and 637,000 Bbls of crude production in 2015, 1.5 Bcf of natural gas production and 533,000 Bbls of crude production in 2016, 373,000 Bbls of crude production in 2017 and 103,000 Bbls of crude production in 2018 as of December 31, 2013. 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 oil, condensate, natural gas and NGLs.

Approximately 44% of our proved reserves are classified as proved developed non-producing or proved undeveloped and may ultimately prove to be less than current reserves estimates.

At December 31, 2013, approximately 44% of our total proved reserves were classified as proved developed non-producing or proved undeveloped. It will take approximately $287.8 million of capital to recomplete or drill our non-producing and undeveloped locations. Our estimate of proved reserves at December 31, 2013 assumes that we will spend in 2014 and 2015 development capital expenditures to develop these reserves of $87.1 million and $28.7 million, 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.

Any disruptions in production, development of proved reserves, or our ability to process and sell oil, condensate, natural gas and NGLs from our properties in the Appalachian Basin 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 and the Mid-Continent area of Oklahoma. Approximately 65% of our oil, condensate, natural gas and NGLs revenues before impact of hedges and approximately 68% of our total proved reserves for the year ended December 31, 2013 were attributable to our properties in the Appalachian Basin area. 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. Since the beginning of 2013, our Marcellus Shale production has been significantly curtailed resulting from issues with high line pressures and unscheduled downtime on the gathering system operated by Williams that services our Marcellus West properties. We estimate that the gathering system downtime for the year ended December 31, 2013 resulted in reduced production of approximately 6.8 MMcfe/d (1.1 MBoe/d), or 13% of total production for the for the year ended December 31, 2013, which reflects the incremental production for the unscheduled downtime assuming an average daily production rate equal to the average daily production immediately prior to the downtime at our actual average monthly sales prices. On July 16, 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs as provided in the agreements. On December 31, 2013, the parties informed the Arbitration Panel that they have reached an agreement in principle to settle their disputes. The settlement is subject to final documentation, which has not yet been completed. At the request of both parties, on January 9, 2014, the Arbitration Panel stayed all proceedings, pending completion of the final

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settlement documentation. While we continue to work with Williams regarding the final settlement agreement, there can be no assurance that such agreement will be finalized quickly or at all.

Approximately 26% of our oil, condensate, natural gas and NGLs revenues before impact of hedges for the year ended December 31, 2013 were attributable to our properties in the Mid-Continent area of Oklahoma. Production in the Mid-Continent could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems.

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

The availability of a ready market for our oil, condensate, natural gas 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. For the year ended December 31, 2013, SEI and Clearfield Appalachia accounted for substantially all of our revenues from the Marcellus Shale. If SEI and Clearfield Appalachia were to cease purchasing and Williams were to cease transporting our natural gas in the Marcellus Shale 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. Alternatively, there are numerous oil, condensate, natural gas and NGLs purchasers in the Mid-Continent area.

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, since the beginning of 2013, our Marcellus Shale production has been significantly curtailed resulting from issues with high line pressures and unscheduled downtime on the gathering system operated by Williams that services our Marcellus West properties. We estimate that the gathering system downtime during the year ended December 31, 2013 resulted in reduced production of approximately 6.8 MMcfe/d (1.1 MBoe/d), or 13% of total production for the year ended December 31, 2013, which reflects the incremental production for the unscheduled downtime assuming an average daily production rate equal to the average daily production immediately prior to the downtime at our actual average monthly sales prices. On July 16, 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs as provided in the agreements. On December 31, 2013, the parties informed the Arbitration Panel that they have reached an agreement in principle to settle their disputes. The settlement is subject to final documentation, which has not yet been completed. At the request of both parties, on January 9, 2014, the Arbitration Panel stayed all proceedings, pending completion of the final settlement documentation. While we continue to work with Williams regarding the final settlement agreement, there can be no assurance that such agreement will be finalized quickly or at all.

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.

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

Our future oil, condensate, natural gas 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

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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 oil or natural gas 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.

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 oil and natural gas 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 oil and natural gas 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 oil or natural gas reserves and of future net cash flows necessarily depend on many variables and assumptions, such as:

- Historical oil or natural gas 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 oil or natural gas 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.

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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 2013, 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 oil or natural gas;
- Actual prices received for oil or natural gas in the future being different than those used in the estimate;
- Curtailments or increases in consumption of oil or natural gas;
- Changes in governmental regulations or taxation; and
- The timing of both production and expenses in connection with the development and production of oil or natural gas properties.

In this Form 10-K, the net present value of estimated future net revenues at December 31, 2013 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 oil and natural gas 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 natural gas properties that can be capitalized on our balance sheet. We may experience write downs of the carrying value of our oil and natural gas properties in the future if the present value of our proved oil and natural gas reserves is lower than our remaining unamortized capitalized costs. If the net capitalized costs of our oil and natural 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 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 our current operating areas 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 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

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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, 2013, 148 gross (25.3 net) wells in which we have an interest were operated by other companies.

The representations, warranties and indemnifications of the Chesapeake Parties contained in the Chesapeake Purchase Agreement and of the Lime Rock Parties contained in the WEHLU Purchase Agreement are limited. As a result, the assumptions on which our estimates of future results of the acquired assets have been based may prove to be incorrect in a number of material ways, resulting in our not realizing the expected benefits of the acquisitions. The acquisitions could also expose us to additional unknown and contingent liabilities.

The representations and warranties of the Chesapeake Parties contained in the Chesapeake Purchase Agreement and of the Lime Rock Parties contained in the WEHLU Purchase Agreement are limited. In addition, these agreements provide limited indemnities. As a result, the assumptions on which our estimates of future results of the acquired assets have been based may prove to be incorrect in a number of material ways, resulting in our not realizing our expected benefits of the acquisitions, including anticipated increased cash flow.

The acquisitions could expose us to additional unknown and contingent liabilities. We have performed a certain level of diligence in connection with the acquisitions and have attempted to verify the representations made by the Chesapeake Parties and the Lime Rock Parties, but there may be unknown and contingent liabilities related to the acquired assets of which we are unaware. The Chesapeake Parties and the Lime Rock Parties have agreed to indemnify us for losses or claims relating to the acquired assets and otherwise subject to the limitations described in the Chesapeake Purchase Agreement and WEHLU Purchase Agreement, respectively. We could be liable for unknown obligations relating to the acquired assets for which indemnification is not available, which could materially adversely affect our business, results of operations and cash flow.

The indenture governing our senior secured notes and the agreement governing our revolving credit facility impose significant operating and financial restrictions, which may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

The indenture governing our 8 5/8% Senior Secured Notes due 2018 (the "Notes") and the documentation governing our current revolving credit facility (the "Revolving Credit Facility") contain customary restrictions on our activities, including covenants that limit our and our subsidiaries' ability to:

- Transfer or sell assets or use asset sale proceeds;
- Incur or guarantee additional debt or issue preferred equity securities;
- Pay dividends, redeem subordinated debt or make other restricted payments;
- Make certain investments;
- Create or incur certain liens on our assets;
- Incur dividend or other payment restrictions affecting our restricted subsidiaries;
- Enter into certain transactions with affiliates;
- Merge, consolidate or transfer all or substantially all of our assets;
- Enter into certain sale and leaseback transactions; and
- Take or omit to take any actions that would adversely affect or impair in any material respect the collateral securing the Notes.

In addition, our Revolving Credit Facility requires us to meet a fixed charge coverage ratio when excess availability under our revolving credit facility is less than a specified level or a specified event of default occurs for a specified duration. See "Financial Statements, Note 4, "Long-Term Debt."

The restrictions in the indenture governing the Notes and in the agreement governing our Revolving Credit Facility may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to

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successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We also may incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. We cannot assure that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all. The breach of any of these covenants and restrictions could result in a default under the indenture governing the Notes or under the agreement governing our Revolving Credit Facility. An event of default under our Revolving Credit Facility could permit some of our lenders to declare all amounts borrowed from them to be due and payable.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Revolving Credit Facility and the Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the Notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the Notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our Notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our Revolving Credit Facility and the indentures governing our Notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

The borrowing base under our Revolving Credit Facility is currently $100.0 million, and there are no borrowings outstanding under the Revolving Credit Facility. Our next scheduled borrowing base redetermination is expected to occur in May 2014. In the future, we may not be able to access adequate funding under our Revolving Credit Facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent semi-annual borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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 oil and 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 Cargill, Inc., Comerica Bank, N.A., ING Capital Markets LLC, Koch Supply & Trading, LP and Wells Fargo Bank, N.A.

From time to time, we are a party to legal proceedings arising in the ordinary course of business.

From time to time, we are subject to various significant legal proceedings and claims arising in the ordinary course of business. No assurance can be given regarding the outcome of these legal proceedings. 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 have been

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incurred in legal proceedings to date and significant expenditures may continue to be incurred in the future. Defense costs and any adverse outcome could adversely affect our business, financial condition and results of operations. For more information on our legal proceedings, see Note 14, "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 oil and natural gas 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 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 oil and natural gas 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. Oil and natural gas 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 any implementing 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
- 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 oil and natural gas. 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. For example, in response to recent seismic events near underground injection wells used for the

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disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells; if new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

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 final permitting guidance in February 2014 addressing the performance of such activities using diesel fuels.

Also, 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 draft 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. Also, in May 2013, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. 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 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 oil and natural gas 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;

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- 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, restoration 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 oil and natural gas 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 oil and natural gas 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.

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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. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also may require us in connection with covered 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.

Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

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 full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts, 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 contractsor 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 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 oil and natural gas 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 oil and natural gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas 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 oil and natural gas business for a much longer time than we have. These companies may be able to pay more for exploratory prospects and productive oil and natural gas 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 oil and natural gas companies. Our ability to explore for oil and natural gas 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 oil and natural gas 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 oil and natural gas 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.

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 five 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 U.S. 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.

Seasonal weather conditions and regulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our common stock price has been and is likely to continue to be highly volatile.

The trading price of our common stock is 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 stock 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 stock 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 stock may adversely affect the price of our common stock.

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

We are able to issue shares of preferred stock with greater rights than our common stock.

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 stockholders. The preferred shares that we have issued rank ahead of our common stock in terms of dividends and liquidation rights. We may

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issue additional preferred shares that rank ahead of our common stock in terms of dividends, liquidation rights or voting rights. If we issue additional preferred shares in the future, it may adversely affect the market price of our common stock.

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

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, the Notes contain covenants that prohibit the payment of dividends and 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, stockholders must look solely to appreciation of our common stock 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 oil and natural gas leases in the following areas:

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

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.

Production, Prices and Operating Expenses

The following table presents information regarding production volumes, average sales prices received and selected data associated with our sales of oil, condensate, natural gas and NGLs for the periods indicated. Unless otherwise specified, all production volumes in this Form 10-K reflect incremental post-processing NGLs volumes and residual gas volumes with which we are credited under our sales contracts.

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	For the Years Ended December 31,		
	2013	2012	2011
Production:			
Natural gas (MMcf)	13,366	10,564	7,318
Oil and condensate (MBbl)	515	177	40
NGLs (MBbl)	494	270	21
Total production (MMcfe)	19,417	13,247	7,684
Total production (MBoe)	3,236	2,208	1,281
Daily Production:			
Natural gas (MMcf/d)	36.6	28.9	20.0
Oil and condensate (MBbl/d)	1.4	0.5	0.1
NGLs (MBbl/d)	1.4	0.7	0.1
Total daily production (MMcfe/d)	53.2	36.2	21.1
Total daily production (MBoe/d)	8.9	6.0	3.5
Average sales price per unit:			
Natural gas per Mcf, excluding impact of hedging activities (1)	$3.02	$2.21	$3.21
Natural gas per Mcf, including impact of hedging activities (1)	$3.43	$3.20	$4.56
Oil and condensate per Bbl, excluding impact of hedging activities (1)	$70.91	$65.45	$85.11
Oil and condensate per Bbl, including impact of hedging activities (1)	$71.04	$70.01	$85.11
NGLs per Bbl, excluding impact of hedging activities (1)	$31.59	$28.22	$52.47
NGLs per Bbl, including impact of hedging activities (1)	$31.13	$34.40	$52.47
Average sales price per Mcfe, excluding impact of hedging activities (1)	$4.76	$3.21	$3.65
Average sales price per Mcfe, including impact of hedging activities (1)	$5.03	$4.19	$4.93
Average sales price per Boe, excluding impact of hedging activities (1)	$28.58	$19.26	$21.89
Average sales price per Boe, including impact of hedging activities (1)	$30.20	$25.14	$29.59
Selected operating expenses (in thousands):			
Production taxes	$4,651	$2,269	$620
Lease operating expenses	$9,456	$6,174	$8,630
Transportation, treating and gathering	$4,006	$4,965	$4,501
Depreciation, depletion and amortization	$32,449	$25,424	$15,216
Impairment of natural gas and oil properties	$—	$150,787	$—
General and administrative expense	$16,961	$12,211	$11,365
Selected operating expenses per Mcfe:			
Production taxes	$0.24	$0.17	$0.08
Lease operating expenses	$0.49	$0.47	$1.12
Transportation, treating and gathering	$0.21	$0.37	$0.59
Depreciation, depletion and amortization	$1.67	$1.92	$1.98
General and administrative expense	$0.87	$0.92	$1.48
Production costs (2)	$0.67	$0.80	$1.62
Selected operating expenses per Boe:			
Production taxes	$1.44	$1.03	$0.48
Lease operating expenses	$2.92	$2.80	$6.74
Transportation, treating and gathering	$1.24	$2.25	$3.51
Depreciation, depletion and amortization	$10.02	$11.52	$11.88
General and administrative expense	$5.24	$5.53	$8.87
Production costs (2)	$4.05	$4.81	$9.71

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(1) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the period presented.
(2) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Drilling Activity

The following table shows our drilling activity for the periods indicated.

	For the Years Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	11.0	5.7	6.0	1.7	20.0	11.9
Non-productive	—	—	—	—	—	—
Total	11.0	5.7	6.0	1.7	20.0	11.9
Development wells:						
Productive	17.0	8.5	31.0	14.2	5.0	1.7
Non-productive	—	—	—	—	—	—
Total	17.0	8.5	31.0	14.2	5.0	1.7

On December 31, 2013, we had a total of 12 gross (6.0 net) operated wells in the process of being drilled or awaiting fracture stimulation in the Marcellus Shale and one gross (0.9 net) operated well and three gross (1.4 net) non-operated wells being drilled or awaiting fracture stimulation 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, 2013.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Marcellus Shale area, West Virginia and Pennsylvania (1)				
Marcellus West	23,721	9,512	7,432	3,547
Marcellus East	47,574	43,804	3,185	2,994
Total Marcellus Shale area	71,295	53,316	10,617	6,541
Mid-Continent	171,089	90,283	38,016	35,684
Total	242,384	143,599	48,633	42,225

(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			Total Expiring	% of Total Undeveloped	
	West	East	Mid-Continent	Gross Acres	Gross Acres	
2014	1,102	10,558	73,993	85,653	35	%
2015	7,692	9,635	40,930	58,257	24	%
2016	3,403	14,780	50,589	68,772	28	%
2017	3,973	52	5,577	9,602	4	%
2018 and thereafter	4,156	7	—	4,163	2	%

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

As of December 31,	Marcellus Shale			Total Expiring	% of Total Undeveloped
	West	East	Mid-Continent	Net Acres	Net Acres
2014	415	9,895	37,945	48,255	34 %
2015	3,387	9,385	21,991	34,763	24 %
2016	1,678	12,410	27,347	41,435	29 %
2017	1,551	52	3,000	4,603	3 %
2018 and thereafter	1,394	7	—	1,401	1 %

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 oil and natural gas 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. We do not assign proved undeveloped reserves to leases after their expiration. Of the 48,255 net acres expiring in 2014, we are currently focusing on net acres expiring in Marcellus West and the Mid-Continent. In Marcellus West, we anticipate drilling on the majority of the acreage before it expires. In the Mid-Continent, approximately 32,600 net acres, or 85%, expiring have automatic lease extension provisions allowing us to extend the lease for an additional two-year term by payment of lease bonus ranging from $400 to $450 per net acre. We plan to make the automatic lease extension payments. We also plan to extend the leases for any additional acreage expiring during 2014 in the Mid-Continent. If we are not able to extend the lease, the acreage will expire. Our current plans in Marcellus East is to let 9,895 net acres scheduled for expiration in 2014 expire.

Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2013. 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 oil or natural gas. 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	98.0	46.7	—	—	98.0	46.7
Mid-Continent, Oklahoma	190.0	86.2	49.0	38.1	239.0	124.3
Total	288.0	132.9	49.0	38.1	337.0	171.0

Oil and Natural Gas Reserves

Reserve Estimation

The SEC rules expand the definition of oil and natural gas 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 year ended December 31, 2013, reserves estimates for the Marcellus Shale and Mid-Continent 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 years ended

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December 31, 2013 and 2012 , Wright evaluated the reserves estimates for the Mid-Continent area 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 99.1 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.

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 to ensure the integrity, accuracy and timeliness of data furnished to Wright in their reserve review and estimation process. Throughout the year, our internal technical team meets regularly with representatives of Wright to review properties and discuss methods and assumptions used in Wright's preparation of the year-end reserves estimates. We provide historical information to Wright for our largest producing properties, including with respect to ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Wright performs an independent analysis, and differences are reviewed with our senior management. In some cases, additional meetings are held to review additional reserve work performed by our technical team related to any identified reserve differences. Historical variances between our internal reserves estimates and Wright'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 reserves report is reviewed by the reserves review committee, together with representatives of Wright and our internal production and engineering team.

Since 2006, all of our reserves estimates have been reviewed and approved by our Senior Reservoir Engineer, who reports directly to our Chief Financial Officer. Our Senior Reservoir Engineer attended Texas A&M University and graduated in 1978 with a Bachelor of Science degree in Reservoir Engineering and has been involved in evaluations and the estimation of reserves and resources for over 31 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, 2013 included in this Form 10-K was estimated by Wright using standard engineering and geosciences procedures and methods used in the petroleum industry. The technical personnel responsible for preparing the reserve estimates at Wright 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.

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In accordance with SEC regulations, estimates of our proved reserves and future net revenues as of December 31, 2013 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 benchmark base prices utilized were the Henry Hub price of $3.67 per MMBtu for natural gas and a WTI spot oil price of $96.78 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 U.S.

The following table summarizes our estimated proved reserves as of December 31, 2013:

	Total Proved Reserves			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	113,193	1,002	66,515	180,710
NGLs (MBbls)	6,017	8	3,773	9,798
Oil and condensate (MBbls)	5,556	278	8,884	14,718
Total proved reserves (MMcfe)	182,632	2,718	142,455	327,805
Total proved reserves (MBoe)	30,439	453	23,742	54,634
PV-10 (in thousands) (1)	$344,075	$13,295	$235,160	$592,530

(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 $333.9 million of net operating loss carryforwards, $50.7 million of foreign tax credit carryforwards and $300.3 million of remaining property tax basis for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, future income taxes discounted at 10% total $76.7 million, resulting in a standardized measure of discounted future net cash flows of $515.8 million as of December 31, 2013.

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The following table summarizes our proved reserves by geographic area as of December 31, 2013:
SEC Pricing Case Proved Reserves (1)

	Natural Gas (MMcf)	NGLs (MBbls)	Oil and Condensate (MBbls)	MMcfe	MBoe	% Proved Developed	PV-10 (2) (in thousands)
Appalachia, West Virginia and Pennsylvania	146,497	7,472	5,013	221,406	36,901	58 %	$ 246,622
Mid-Continent	34,213	2,326	9,705	106,399	17,733	54 %	345,908
Total	180,710	9,798	14,718	327,805	54,634	57 %	$ 592,530

(1) Key benchmark base prices utilized were the Henry Hub price of $3.67 per MMBtu for natural gas and a WTI spot oil price of $96.78 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 $333.9 million of net operating loss carryforwards, $50.7 million of foreign tax credit carryforwards and $300.3 million of remaining property tax basis for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, future income taxes discounted at 10% total $76.7 million, resulting in a standardized measure of discounted future net cash flows of $515.8 million as of December 31, 2013.

Proved Undeveloped Reserves (“PUDs”)

As of December 31, 2013, our PUDs totaled 142.5 Bcfe (23.7 MMBoe), representing a 162% increase from our PUDs as of December 31, 2012. As of December 31, 2013, 93.3 Bcfe (15.5 MMBoe) of PUDs were associated with the Marcellus Shale and 49.2 Bcfe (8.2 MMBoe) of PUDs were associated with the Mid-Continent. The December 31, 2013 PUDs consisted of 40 gross (18.8 net) Marcellus Shale horizontal wells and 73 gross (65.3 net) wells in the Mid-Continent. The increase in PUD well locations in 2013 is due to the successful Marcellus Shale drilling program in 2013 and the successful results of our Mid-Continent drilling program and the acquisition of additional leasehold in the area during 2013, partially offset by 23.7 Bcfe of 2012 PUD reserves that we converted to proved developed reserves in 2013 through the completion of the 12 gross (6.0 net) Marcellus Shale wells. The net cost of converting such PUDs to proved developed reserves during 2013 was $22.7 million.

The following table summarizes our PUD activity during the year ended December 31, 2013:

	Natural Gas (MMcf)	NGLs (MBbls)	Oil and Condensate (MBbls)	MMcfe	MBoe
PUDs as of December 31, 2012	35,409	1,707	1,435	54,256	9,043
Extensions and discoveries	40,744	1,922	3,001	70,283	11,714
Purchases of reserves in place	4,799	768	4,990	39,347	6,558
PUDs converted to proved developed	(15,326)	(741)	(573)	(23,212)	(3,869)
Revisions of previous estimates	890	117	31	1,781	297
PUDs as of December 31, 2013	66,516	3,773	8,884	142,455	23,743

Estimated future development costs relating to the development of 2013 year-end PUDs is $278.6 million, of which 2014 and 2015 expenditures are $83.4 million and $28.2 million, respectively. Under current SEC requirements, PUD reserves may only be booked if they relate 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, 2013 are scheduled to be drilled by 2018, 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 14, “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 Parent's common stock during the periods presented.

	NYSE MKT LLC	
	High	Low
2013:		
Fourth quarter	$6.92	$3.94
Third quarter	$4.52	$2.64
Second quarter	$3.07	$1.95
First quarter	$1.79	$1.05
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

The last reported sale price of our common stock on the NYSE MKT on March 11, 2014 was $5.68. In connection with the merger of Parent with and into Gastar USA on January 31, 2014, shares of Parent's common stock ceased trading on the NYSE MKT LLC on January 31, 2014 and shares of Gastar Exploration Inc.'s common stock commenced trading on the NYSE MKT LLC under the ticker symbol “GST,” the same symbol that Parent's common stock traded under prior to the merger.
Stockholders
As of March 11, 2014, there were 327 stockholders of record who owned shares of our common stock.
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 stock as long as any debt remains outstanding under the facility.
We 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, and on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference, or $2.6875 per share outstanding each year, of no more than $20.0 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 Equity Securities; Use of Proceeds from Sales of Unregistered Equity Securities
We did not have any sales of unregistered equity securities during the year ended December 31, 2013.

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Item 6. Selected Financial Data

The following table presents selected historical financial data for Parent and its subsidiaries as of and for the periods indicated. The selected consolidated financial data are derived from our audited consolidated financial statements. The following selected historical 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 year ended December 31, 2013 includes a gain on acquisition of assets at fair value of $27.7 million. Financial information as of and for the years ended December 31, 2012 and 2009 includes impairment of oil and natural gas properties of $150.8 million and $68.7 million, respectively. Financial information as of and for the years ended December 31, 2013, 2012 and 2010 includes litigation settlement expense of $1.0 million, $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,				
	2013	2012	2011	2010	2009
	(in thousands, except per share data)				
Consolidated Statements of Operations:					
Revenues	$87,755	$49,940	$40,235	$42,768	$32,869
Income (loss) from operations	$18,764	$(153,528)	$(631)	$(15,019)	$(76,930)
Net income (loss) attributable to Gastar Exploration, Inc.	$39,964	$(160,868)	$(1,764)	$(12,460)	$48,846
Net income (loss) attributable to Gastar Exploration, Inc. per share:					
Basic	$0.66	$(2.53)	$(0.03)	$(0.25)	$1.06
Diluted	$0.63	$(2.53)	$(0.03)	$(0.25)	$1.06
Weighted average shares of common stock outstanding					
Basic	60,220	63,538	63,004	49,814	46,103
Diluted	63,618	63,538	63,004	49,814	46,210
Consolidated Balance Sheets:					
Property, plant and equipment, net	$517,513	$256,251	$285,740	$215,115	$162,661
Total assets	$589,935	$290,068	$334,503	$247,352	$296,238
Long-term liabilities	$325,802	$106,020	$39,438	$14,295	$18,371
Total stockholders' equity	$83,207	$49,895	$207,803	$207,391	$164,896

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

You should read the following discussion of our historical performance, financial condition and future prospects in conjunction with the audited financial statements of Gastar Exploration, Inc. (formerly known as Gastar Exploration Ltd.) and its subsidiaries as of and for the years ended December 31, 2013 and 2012 and the audited financial statements of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) and its subsidiaries as of and for the years ended December 31, 2013 and 2012 and the notes thereto included elsewhere in this Form 10-K. At December 31, 2013, Gastar Exploration, Inc. was a holding company and substantially all of its operations were conducted through, and substantially all of its assets were held by, its primary operating subsidiary, Gastar Exploration USA, Inc. and its wholly-owned subsidiaries. Subsequently, on January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar Exploration USA, Inc. as part of a reorganization to eliminate the holding company corporate structure. Pursuant to the merger agreement, shares of the Gastar Exploration Inc.'s common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to "Gastar Exploration Inc." Gastar Exploration Inc., together with its subsidiaries, owns and will continue to conduct business in substantially the same manner as was being conducted by Gastar Exploration, Inc. and its subsidiaries

prior to the merger.
Overview

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We are an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas 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 development within the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play in Oklahoma and the development of liquids-rich natural gas in the Marcellus Shale play in West Virginia. We also hold prospective Utica Shale acreage in West Virginia and prospective Marcellus Shale acreage in Pennsylvania. We completed the sale of substantially all of our East Texas assets on October 2, 2013, with an effective date of January 1, 2013.

On November 14, 2013, Parent changed its jurisdiction of incorporation to the State of Delaware and changed its name to “Gastar Exploration, Inc.” On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar USA as part of a reorganization to eliminate the holding company corporate structure of Parent. Pursuant to the merger agreement, shares of Parent’s common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to “Gastar Exploration Inc.” Gastar Exploration Inc., together with its subsidiaries, owns and will continue to conduct Gastar’s business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger. Gastar USA's Series A Preferred Stock and Series B Preferred Stock are listed on the NYSE MKT under the symbols “GST.PRA” and “GST.PRB,” respectively.

All of our current operational activities are conducted primarily in the U.S. As of December 31, 2013, our major assets consist of approximately 81,900 gross (59,900 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania and approximately 209,100 gross (126,000 net) acres in the Mid-Continent area of the U.S. in the state of Oklahoma. During the past three years, we spent approximately $596.7 million in property acquisitions, acreage, seismic, capitalized interest, drilling advances, reserve acquisition and exploratory and development drilling on this acreage. We attained positive net income from operations during 2013 primarily due to the recognition of a gain on acquisition of assets at fair value of $27.7 million, but 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 oil, condensate, natural gas and NGLs;
- The level of total sales volumes of oil, condensate, natural gas 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 oil, condensate, natural gas and NGLs prices that are influenced by many factors beyond our control. We focus our efforts on increasing oil, condensate, natural gas 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 oil, condensate, natural gas and NGLs prices in future periods.

Like other oil and natural gas exploration and production companies, we face natural production declines. As initial reservoir pressures are depleted, oil, condensate, natural gas and NGLs production from a given well will decrease. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil, condensate, natural gas 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.

2013 Highlights

Marcellus Shale Drilling Program. During the year ended December 31, 2013, we drilled and completed 19 gross (9.5 net) operated wells in Marshall County, West Virginia, under the Atinum Joint Venture and had 3 gross (1.5 net) operated wells drilled and awaiting completion. At December 31, 2013, we had 57 gross (27.0 net) operated wells on production in Marshall County, West Virginia. At December 31, 2013, our proved reserves attributable to our Marcellus Shale acreage were approximately 221.4 Bcfe (36.9 MMBoe), a significant increase from year-end 2012 reserves of 153.2 Bcfe (25.5 MMBoe). Marcellus Shale proved reserves represented approximately 68% of our total proved reserves at December 31, 2013. Oil, condensate and NGLs reserves comprised approximately 34% of the total Marcellus Shale proved reserves at year end 2013.

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Mid-Continent Horizontal Oil Play. At December 31, 2013, we held leases covering approximately 209,100 gross (126,000 net) acres in the Mid-Continent horizontal oil play and had completed our first two gross (1.7 net) operated wells in the play. On June 7, 2013, we acquired approximately 157,000 net acres of oil and natural gas leasehold interests in Canadian and Kingfisher Counties, Oklahoma from the Chesapeake Parties, including production interests in 206 producing wells for an adjusted cash purchase price of approximately $69.4 million (reflecting adjustment for an acquisition effective date of October 1, 2012). Effective July 1, 2013, our working interest partner in our original AMI in Oklahoma exercised its rights to acquire approximately 12,800 net acres and certain proved properties that we had acquired pursuant to the Chesapeake Purchase Agreement for a total net payment of $11.6 million (reflecting adjustment for an acquisition effective date of October 1, 2012). On August 6, 2013, we sold approximately 76,000 net undeveloped acres in Kingfisher and Canadian Counties, Oklahoma to Newfield for an adjusted purchase price of approximately $57.0 million cash net of the purchase of approximately 1,850 net acres of Oklahoma oil and gas leasehold interests from Newfield for $1.5 million. On November 15, 2013, we acquired a 98.3% working interest (80.5% net revenue interest) in 24,000 net acres of oil and natural gas leasehold interests in the WEHLU located in Kingfisher, Logan and Oklahoma Counties, Oklahoma, including production from interests in 56 gross (55.0 net) producing wells, for an adjusted cash purchase price of approximately $177.8 million, including an effective date adjustment to August 1, 2013. At December 31, 2013, our proved reserves attributable to our Mid-Continent acreage were approximately 106.4 Bcfe (17.7 MMBoe). Mid-Continent proved reserves represented approximately 32% of our total proved reserves at December 31, 2013. Oil, condensate and NGLs reserves comprised approximately 68% of the total Mid-Continent proved reserves at year end 2013.

Financial Highlights

Our consolidated financial statements reflect total revenue of $87.8 million on total volumes of 19.4 Bcfe (3.2 MMBoe) for the year ended December 31, 2013. Our operating income for the year ended December 31, 2013 was $18.8 million and included depreciation, depletion and amortization expense of $32.4 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.

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,		
	2013	2012	2011
	(In thousands, except per unit amounts)		
Revenues:			
Natural gas	$40,416	$23,318	$23,523
Oil and condensate	36,480	11,570	3,416
NGLs	15,611	7,630	1,092
(Loss) gain on commodity derivatives contracts	(4,752)	7,422	12,204
Total revenues	$87,755	$49,940	$40,235
Production:			
Natural gas (MMcf)	13,366	10,564	7,318
Oil and condensate (MBbl)	515	177	40
NGLs (MBbl)	494	270	21
Total production (MMcfe)	19,417	13,247	7,684
Total production (MBoe)	3,236	2,208	1,281
Natural gas (MMcf/d)	36.6	28.9	20.0
Oil and condensate (MBbl/d)	1.4	0.5	0.1
NGLs (MBbl/d)	1.4	0.7	0.1
Total daily production (MMcfe/d)	53.2	36.2	21.1
Total daily production (MBoe/d)	8.9	6.0	3.5
Average sales price per unit:			
Natural gas per Mcf, excluding impact of hedging activities	$3.02	$2.21	$3.21
Natural gas per Mcf, including impact of hedging activities (1)	$3.43	$3.20	$4.56
Oil and condensate per Bbl, excluding impact of hedging activities	$70.91	$65.45	$85.11
Oil and condensate per Bbl, including impact of hedging activities (1)	$71.04	$70.01	$85.11
NGLs per Bbl, excluding impact of hedging activities	$31.59	$28.22	$52.47
NGLs per Bbl, including impact of hedging activities (1)	$31.13	$34.40	$52.47
Average sales price per Mcfe, excluding impact of hedging activities	$4.76	$3.21	$3.65
Average sales price per Mcfe, including impact of hedging activities (1)	$5.03	$4.19	$4.93
Average sales price per Boe, excluding impact of hedging activities	$28.58	$19.26	$21.89
Average sales price per Boe, including impact of hedging activities (1)	$30.20	$25.14	$29.59
Selected operating expenses (in thousands):			
Production taxes	$4,651	$2,269	$620
Lease operating expenses	$9,456	$6,174	$8,630
Transportation, treating and gathering	$4,006	$4,965	$4,501
Depreciation, depletion and amortization	$32,449	$25,424	$15,216
Impairment of natural gas and oil properties	$—	$150,787	$—
General and administrative expenses	$16,961	$12,211	$11,365
Selected operating expenses per Mcfe:			
Production taxes	$0.24	$0.17	$0.08
Lease operating expenses	$0.49	$0.47	$1.12

Transportation, treating and gathering	$0.21	$0.37	$0.59
Depreciation, depletion and amortization	$1.67	$1.92	$1.98

General and administrative expenses (2)	$0.87	$0.92	$1.48
Selected operating expenses per Boe:			
Production taxes	$1.44	$1.03	$0.48
Lease operating expenses	$2.92	$2.80	$6.74
Transportation, treating and gathering	$1.24	$2.25	$3.51
Depreciation, depletion and amortization	$10.02	$11.52	$11.88
General and administrative expenses (2)	$5.24	$5.53	$8.87

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(1) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the period presented.

(2) The 2013 general and administrative expenses include $2.6 million of non-recurring acquisition and migration costs. Excluding such acquisition costs, general and administrative expenses would have been $0.74 per Mcfe ($4.43 per Boe).

Year Ended December 31, 2013 compared to Year Ended December 31, 2012

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $92.5 million for the year ended December 31, 2013, up 118% from $42.5 million for the year ended December 31, 2012. The increase in revenues was the result of a 47% increase in production coupled with a 48% increase in weighted average realized prices. Average daily production on an equivalent basis was 53.2 MMcfe/d (8.9 MBoe/d) for the year ended December 31, 2013 compared to 36.2 MMcfe/d (6.0 MBoe/d) for the same period in 2012. During 2013, production in the Marcellus Shale averaged 39.2 MMcfe/d (6.5 MBoe/d) compared to 2012 production of 22.0 MMcfe/d (3.7 MBoe/d), a 78% increase. For the year ended December 31, 2013, production in the Mid-Continent averaged 6.5 MMcfe/d (1.1 MBoe/d) compared to 2012 production of 0.03 MMcfe/d (0.01 MBoe/d). During 2013, production in East Texas averaged 7.5 MMcfe/d (1.2 MBoe/d) compared to 2012 production of 13.7 MMcfe/d (2.3 MBoe/d), a 45% decrease due to the sale of our interest in the East Texas wells on October 2, 2013. Oil, condensate and NGLs production represented approximately 31% of total production for the year ended December 31, 2013 compared to 20% of total production for the year ended December 31, 2012.

Liquids revenues (oil, condensate and NGLs) represented approximately 56% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2013 compared to approximately 45% for the year ended December 31, 2012. We are continuing to focus our 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 oil, condensate and NGLs prices continue, and assuming that we successfully and timely complete our 2014 drilling activity, we expect our liquids revenues to continue to increase as a percentage of total oil, condensate, natural gas and NGLs revenues in 2014.

During the year ended December 31, 2013, we had commodity derivative contracts covering approximately 72% of our natural gas production, which resulted in gains on natural gas commodity derivatives contracts settled during the year of $5.4 million and an increase in total price realized from $3.02 per Mcf to $3.43 per Mcf. The gains on commodity derivatives contracts settled during the year includes a loss of $27,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $5.4 million, which was comprised of $5.5 million of NYMEX hedge gains partially offset by $129,000 of regional basis losses. During the year ended December 31, 2012, the impact of hedging on natural gas sales was an increase of $10.5 million in natural gas revenues resulting in an increase in total price realized from $2.21 per Mcf to $3.20 per Mcf. The 2012 hedge impact included a benefit of $884,000 of non-cash amortization of prepaid premiums and payment of deferred put premiums of $4.5 million.

During the year ended December 31, 2013, we had commodity derivative hedge contracts covering approximately 51% of our oil and condensate production. The impact of hedging on oil and condensate sales was an increase of $69,000 in oil and condensate revenues resulting in an increase in total price realized from $70.91 per Bbl to $71.04 per Bbl. The gains on oil and condensate commodity derivatives contracts settled during the year includes a loss of $2,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on oil and condensate sales was an increase in revenues of $71,000, which was comprised of $154,000 of NYMEX hedge gains partially offset by the payment of deferred put premiums of $83,000. We have designated a portion of our current crude hedges as price protection for our NGLs production.

During the year ended December 31, 2013, we had commodity derivative hedge contracts covering approximately 83% of our NGLs production. The impact of hedging on NGLs sales was a decrease of $227,000 in NGLs revenues resulting in a decrease in total price realized from $31.59 per Bbl to $31.13 per Bbl. The NGLs commodity derivatives contracts settled during the year includes a loss of $2,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the

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impact of hedging on NGLs sales was a decrease in revenues of $225,000, which was comprised of $142,000 of NYMEX hedge losses coupled with the payment of deferred put premiums of $83,000.

Losses related to the change in mark to market value for outstanding commodity derivatives contracts for the year ended December 31, 2013 were $10.0 million compared to losses of $5.6 million for the year ended December 31, 2012. The increase in the mark to market loss is primarily the result of lower future hedge prices and higher future NYMEX natural gas prices.

Production taxes. We reported production taxes of approximately $4.7 million for the year ended December 31, 2013, up from $2.3 million for the year ended December 31, 2012. The increase in production taxes is the result of higher revenues in West Virginia and Oklahoma due to increased oil, condensate, natural gas and NGLs production.

Lease operating expenses. We reported lease operating expenses ("LOE") of $9.5 million for the year ended December 31, 2013, up from $6.2 million for the year ended December 31, 2012. This increase in our LOE was primarily due to a $3.9 million increase in our direct LOE and workover expense due to increased operations in Oklahoma partially offset by a $464,000 decrease in workover expense resulting from decreased workovers in East Texas. Our LOE was $0.49 per Mcfe ($2.92 per Boe) for the year ended December 31, 2013, up 4% from $0.47 per Mcfe ($2.80 per Boe) for the same period in 2012. Excluding workover expense and other non-recurring costs, our LOE was $9.2 million or $0.47 per Mcfe ($2.83 per Boe) for the year ended December 31, 2013, compared to $5.4 million or $0.41 per Mcfe ($2.45 per Boe) for the same period in 2012. A summary of LOE by area is as follows:

	Lease Operating Expense For the Year Ended December 31, 2013			Lease Operating Expense For the Year Ended December 31, 2012			% Change of $ per Mcfe and Boe
	(in thousands)	($ per Mcfe)	($ per Boe)	(in thousands)	($ per Mcfe)	($ per Boe)	
Mid-Continent	$4,018	$1.69	$10.17	$33	$3.13	$18.79	(46)%
Appalachia	3,181	$0.22	$1.33	2,071	$0.26	$1.54	(13)%
East Texas	2,253	$0.83	$4.97	3,624	$0.72	$4.35	14%
Other	4	$0.26	$1.57	446	$2.57	$15.43	(90)%
Total	$9,456	$0.49	$2.92	$6,174	$0.47	$2.80	4%

The 46% decrease from December 31, 2012 to December 31, 2013 in LOE per Mcfe and Boe for the Mid-Continent is the result of increased production. The 13% decrease from December 31, 2012 to December 31, 2013 in LOE per Mcfe and Boe for Appalachia area was primarily the result of increased production. The 14% increase from December 31, 2012 to December 31, 2013 in LOE per Mcfe and Boe for the Hilltop area, East Texas was primarily the result of lower volumes and decreased total LOE expense due to the sale of our interest in the properties on October 2, 2013. The 90% decrease from December 31, 2012 to December 31, 2013 in LOE per Mcfe and Boe 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 $4.0 million for the year ended December 31, 2013, down from $5.0 million for the year ended December 31, 2012. This decrease was primarily due to lower transportation costs in East Texas of $924,000 as a result of the sale of our interest in the properties on October 2, 2013. The year ended December 31, 2013 includes $1.8 million of minimum volume requirement charges under our Hilltop gas gathering agreement compared to $2.0 million of such charges in the same period of 2012. The minimum volume requirement charges result from actual production volumes being less than minimum contractual volume requirements. The purchaser of our East Texas properties has assumed any future minimum volume requirement obligations.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") was $32.4 million for the year ended December 31, 2013, up from $25.4 million for the year ended December 31, 2012. The increase in DD&A expense was the result of a 47% increase in total production volumes attributable to increased Marcellus Shale and Mid-Continent production, which was partially offset by a 13% decrease in the DD&A rate per Mcfe and per Boe.

The DD&A rate for the year ended December 31, 2013 was $1.67 per Mcfe ($10.02 per Boe), as compared to $1.92

per Mcfe ($11.52 per Boe) for the same period in 2012. The decrease in the DD&A rate per Mcfe is primarily due to increased production volumes and lower proved costs resulting from the sale of our East Texas properties and the $150.8 million of ceiling impairments recorded during 2012.

Impairment of natural gas and oil properties. We did not recognize an impairment for the year ended December 31, 2013. Impairment of natural gas and oil properties was $150.8 million for the year ended December 31, 2012. The 2012 impairment was 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. Should there be declines in the 12-month average oil, condensate, natural gas, condensate NGLs prices, we could recognize additional ceiling impairments in the future.

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General and administrative expenses. We reported general and administrative expenses of approximately $17.0 million for the year ended December 31, 2013, up from $12.2 million for the year ended December 31, 2012. Non-cash stock-based compensation expense, which is included in general and administrative expenses, was $3.4 million and $3.3 million for the years ended December 31, 2013 and 2012, respectively. Excluding stock-based compensation expense, general and administrative expense increased $4.6 million to $13.5 million for the year ended December 31, 2013 compared to $8.9 million for the year ended December 31, 2012. The $4.6 million increase in 2013 is primarily due to $2.4 million of acquisition costs related to the Chesapeake Assets and WEHLU acquisitions, a $362,000 increase in costs associated with the migration of Parent from Canada to the U.S. and a $1.6 million increase related to additional staff to oversee the operation and administration of our growing property base.
Litigation settlement expense. We reported litigation settlement expense of $1.0 million for the twelve months ended December 31, 2013 resulting from our settlement with Chesapeake in June 2013 compared to $1.3 million for the year ended December 31, 2012 resulting from our settlement with Navasota in April 2012. For additional information regarding the settlement of this matter, see Note 14, “Commitments and Contingencies Litigation,” to our consolidated financial statements included in this Form 10-K.
Gain on acquisition of assets at fair value. We reported a bargain purchase gain of $27.7 million for the year ended December 31, 2013 for the acquisition of the Chesapeake Assets. Our preliminary assessment of the fair value of the Chesapeake Assets resulted in a fair market valuation of $113.1 million. As a result of incorporating the valuation information into the purchase price allocation, a bargain purchase gain of $27.7 million was recognized. The bargain purchase gain was primarily attributable to the non-strategic nature of the divestiture to the seller, coupled with favorable economic trends in the industry and the geographic region in which the Chesapeake Assets are located.
Interest expense. We reported interest expense of $13.2 million for the year ended December 31, 2013 compared to $270,000 for the year ended December 31, 2012. Interest expense excludes $3.3 million and $1.9 million of capitalized interest in 2013 and 2012, respectively, which related to capital expenditures for undeveloped projects in West Virginia and the Mid-Continent. Excluding capitalized interest, interest expense increased $14.2 million from December 31, 2012 to December 31, 2013 primarily due to higher outstanding debt balances at higher interest rates throughout the year ended December 31, 2013 as a result of the issuance of $325.0 million of our 8 5/8% Senior Secured Notes due 2018 issued during the year and increased amortization of debt costs including a non-recurring cost of $1.2 million related to the termination of our revolving credit facility.
Provision for income tax expense (benefit). We reported an income tax benefit of $16.0 million for the year ended December 31, 2013 attributable to the release of a portion of our valuation allowance against our net deferred tax asset. We recorded a net deferred tax liability of $16.0 million as a result of the Chesapeake Acquisition which reduced our existing net deferred tax asset position, resulting in a corresponding reduction in the valuation allowance against the net deferred tax asset.
Dividends on Preferred Stock. We reported dividends on preferred stock of $9.4 million for the year ended December 31, 2013 compared to $7.1 million for the year ended December 31, 2012. The Series A Preferred Stock had a stated value of approximately $76.8 million and $76.6 million at December 31, 2013 and 2012, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $8.5 million and $7.1 million for the years ended December 31, 2013 and 2012, respectively. The increase in dividends on Series A Preferred Stock is due to the issuance of 6,906 preferred shares during the year ended December 31, 2013. The Series B Preferred Stock, issued during November 2013, had a stated value of approximately $50.0 million at December 31, 2013 and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $847,000 for the year ended December 31, 2013. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at December 31, 2013, our future stated preferred dividend expense is approximately $3.5 million per quarter, which is subject to being declared and paid monthly.
Year Ended December 31, 2012 compared to Year Ended December 31, 2011
Revenues. Total oil, condensate, natural gas and NGLs revenues were $42.5 million for the year ended December 31, 2012, up 52% from $28.0 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 12% decrease in weighted average realized prices. Average daily production on an equivalent basis was 36.2 MMcfe/d (6.0 MBoe/d) for the year ended December 31,

2012 compared to 21.1 MMcfe/d (3.5 MBoe/d) for the same period in 2011. During 2012, production in Appalachia averaged 22.0 MMcfe/d (3.7 MBoe/d) compared to 2011 production of 2.4 MMcfe/d (0.4 MBoe/d), an 817% increase. During 2012, production in East Texas averaged 13.7 MMcfe/d (2.3 MBoe/d) compared to 2011 production of 17.3 MMcfe/d (2.9 MBoe/d), a 21% decrease. Oil, condensate 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 (oil, condensate and NGLs) represented approximately 45% of our total oil, condensate natural gas and NGLs revenues for the year ended December 31, 2012 compared to approximately 16% for the year ended December 31, 2011.

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During the year ended December 31, 2012, we had commodity derivative contracts covering approximately 68% of our natural gas production, which resulted in gains on natural gas commodity derivatives contracts settled during the year of $10.5 million and an increase in total price realized from $2.21 per Mcf to $3.20 per Mcf. The hedge impact includes a benefit of $884,000 for amortization of prepaid call sale premiums. Excluding the non-cash amortization, the 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 impact 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 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 oil and condensate production. The effect of hedging on oil and condensate sales was an increase of $807,000 in oil and condensate 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 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.

Losses related to the change in mark to market value for outstanding commodity derivatives contracts for the year ended December 31, 2012 was $5.6 million compared to a gain of $2.3 million for the year ended December 31, 2011. The increase in the mark to market 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 was the result of higher revenues in West Virginia due to increased oil, condensate, natural gas 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 ($2.80 per BOE) for the year ended December 31, 2012, down 58% from $1.12 per Mcfe ($6.74 per Boe) 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 ($2.45 per Boe) for the year ended December 31, 2012, compared to $6.5 million or $0.85 per Mcfe ($5.10 per Boe) for the same period in 2011. A summary of LOE by area is as follows:

	Lease Operating Expense For the Year Ended December 31, 2012			Lease Operating Expense For the Year Ended December 31, 2011			% Change of $ per Mcfe and Boe
	(in thousands)	($ per Mcfe)	($ per Boe)	(in thousands)	($ per Mcfe)	($ per Boe)	
East Texas	$3,624	$ 0.72	$4.35	$5,863	$ 0.93	$5.58	(23)%
Appalachia	2,071	$ 0.26	$1.54	832	$ 0.97	$5.80	(73)%
Other	479	$ 2.60	$15.62	1,935	$ 3.72	$22.35	(30)%
Total	$6,174	$ 0.47	$2.80	$8,630	$ 1.12	$6.74	(58)%

The 23% decrease from December 31, 2011 to December 31, 2012 in LOE per Mcfe and Boe 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 ($0.92 per Boe) and $0.33 per Mcfe ($1.97 per Boe), respectively. The 73% decrease from December 31, 2011 to December 31, 2012 in LOE per Mcfe and Boe for Appalachia was primarily the result of increased production. The 30% decrease from December 31, 2011 to December 31, 2012 in LOE per Mcfe and Boe 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 ($11.52 per Boe) as compared to $1.98 ($11.88 per Boe) for the same period in 2011. The decrease in the DD&A rate per Mcfe was 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 was 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.

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 year ended December 31, 2012 resulting from our settlement with Navasota in April 2012. For additional information regarding the settlement of this matter, see Note 14, “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 our 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 was 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.

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 our 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, 2013, we reported cash flows provided by operating activities of $47.8 million. For the year ended December 31, 2013, we reported net cash used in investing activities of $265.5 million, primarily for the acquisition, development and purchase of natural gas and oil properties, including $69.4 million for the purchase of the Chesapeake Assets and $177.8 million for the purchase of the WEHLU Assets reduced by $112.2 million of property sales. For the year ended December 31, 2013, we reported net cash provided by financing activities of $241.2 million, consisting of $50.2 million of net proceeds from issuances of 6,906 shares of our Series A Preferred Stock and 2,140,000 shares of our Series B

Preferred Stock, $312.3 million of net proceeds from the issuance of Notes less $98.0 million of net repayments under our revolving credit facility, $9.8 million for the repurchase of common shares, $9.4 million of dividends paid on preferred stock and $3.8 million of deferred financing charges. As a result of these activities, our cash and cash equivalents balance increased by $23.5 million, resulting in a December 31, 2013 balance of cash and cash equivalents of $32.4 million. Net cash provided by operating activities increased $10.8 million from 2012 primarily due to increased oil, condensate, natural gas and NGLs revenues in 2013 resulting from a 47% increase in production. Cash flow used in investing activities increased $117.3 million from 2012 to 2013 primarily due to increased development and purchase of natural gas and oil properties during 2013 in the Mid-Continent.

At December 31, 2013, we had a net working capital surplus of approximately $1.1 million, including $9.3 million of advances from non-operators. At December 31, 2013, availability under the Revolving Credit Facility was $100.0 million.

Future capital and other expenditure requirements. Capital expenditures for 2014 are projected to be approximately $191.8 million. In the Marcellus Shale and Mid-Continent, we expect to spend $68.5 million and $114.1 million, respectively, for drilling, completion, infrastructure, lease acquisition and seismic costs. In addition, we have allocated $9.1 million for capitalized interest and other costs. We plan to fund our 2014 capital budget through existing cash balances, internally generated cash flow from operating activities, borrowings under the Revolving Credit Facility, possible divestiture of assets and the possible issuance of debt or equity securities or some combination thereof. 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 oil, condensate, natural gas 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 76% of our budgeted 2014 capital expenditures, and thus, we could reduce a significant portion of 2014 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 oil, condensate, natural gas 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 oil, condensate, natural gas 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 oil, condensate, natural gas and NGLs price risk. 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 a portion of our NGLs production.

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As of December 31, 2013, 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	Ceiling (Short)
		(in MMBtu's)					
2014	Fixed price swap	11,136	4,064,500	$4.06	$—	$—	$—
2014	Fixed price swap	2,000	730,000	3.72	—	—	—
2014	Fixed price swap	2,000	730,000	3.98	—	—	—
2014	Fixed price swap	2,000	730,000	4.07	—	—	—
2014	Short calls	2,500	912,500	—	—	—	4.59
2014	Costless collar	3,000	1,095,000	—	4.00	—	4.36
2014	Costless collar	5,000	1,825,000	—	4.00	—	4.55
2014	Costless collar	2,500	912,500	—	4.00	—	4.71
2014 (1)	Short puts	10,500	966,000	—	—	3.00	—
2015	Fixed price swap	400	146,000	4.00	—	—	—
2015	Fixed price swap	2,500	912,500	4.06	—	—	—
2015	Protective spread	2,600	949,000	4.00	—	3.25	—
2015	Costless three-way collar	2,000	760,000	—	4.00	3.25	4.58
2016	Protective spread	2,000	732,000	4.11	—	3.25	—
2016	Costless three-way collar	2,000	732,000	—	4.00	3.25	4.58

(1) For the period October to December 2014.

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As of December 31, 2013, 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	Ceiling (Short)
2014 (2)	Fixed price swap	300	54,300	$ 98.05	$—	$—	$—
2014 (2)	Fixed price swap	550	99,550	95.15	—	—	—
2014 (2)	Fixed price swap	900	162,900	93.21		—	—
2014 (3)	Fixed price swap	750	138,000	90.35	—	—	—
2014 (3)	Fixed price swap	200	36,800	93.00	—	—	—
2014 (3)	Fixed price swap	350	64,400	91.55	—	—	—
2014	Fixed price swap	500	182,500	91.10	—	—	—
2014	Fixed price swap	270	98,500	90.77	—	—	—
2014	Costless collar	200	73,000	—	98.00	—	98.00
2014 (4)	Put spread	200	24,400	—	93.00	73.00	—
2015	Costless three-way collar	400	146,000	—	85.00	70.00	96.50
2015	Costless three-way collar	345	126,100	—	85.00	65.00	97.80
2015 (5)	Costless three-way collar	150	27,150	—	85.00	65.00	96.25
2015 (6)	Costless three-way collar	50	9,200	—	85.00	65.00	96.25
2015 (5)	Put spread	700	126,700	—	90.00	70.00	—
2015	Put spread	250	91,250	—	89.00	69.00	—
2015 (6)	Put spread	600	110,400	—	87.00	67.00	—
2016	Costless three-way collar	275	100,600	—	85.00	65.00	95.10
2016	Costless three-way collar	330	120,780	—	80.00	65.00	97.35
2016	Put spread	550	201,300	—	85.00	65.00	—
2016	Put spread	300	109,800	—	85.50	65.50	—
2017	Costless three-way collar	280	102,200	—	80.00	65.00	97.25
2017	Costless three-way collar	242	88,150	—	80.00	60.00	98.70
2017	Put spread	500	182,500	—	82.00	62.00	—
2018 (7)	Put spread	425	103,275	—	80.00	60.00	—

(1) Crude volumes hedged include oil, condensate and certain components of our NGLs production.
(2) For the period January to June 2014.
(3) For the period July to December 2014.
(4) For the period September to December 2014.
(5) For the period January to June 2015.
(6) For the period July to December 2015.
(7) For the period January to August 2018.

See Note 7, "Derivative Instruments and Hedging Activity" to our consolidated financial statements, which begin on page F-1 of this Form 10-K.

At December 31, 2013, the estimated fair value of all of our commodity derivative instruments was a net asset of $3.8 million, comprised of current and non-current assets and liabilities. In conjunction with certain derivative hedging activity, we deferred the payment of certain put premiums for the production month period January 2014 through August 2018. At December 31, 2013, we had a current commodity derivative premium payable of $145,000 and a long-term commodity derivative premium payable of $7.0 million. The put premium liabilities are payable monthly as the hedge production month becomes the prompt production month.

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By removing the price volatility from a portion of our oil, condensate and natural gas sales for 2014 to 2018, 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, 2013, all of our economic derivative hedge positions were with 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, 2013 is provided under the Revolving Credit Facility through intercreditor agreements. We are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, we do not anticipate non-performance by such counterparties.
Revolving Credit Facility. Effective June 7, 2013, we amended and restated our revolving credit facility. As amended, our Revolving Credit Facility had an initial borrowing base of $50.0 million. On December 9, 2013, the borrowing base under the Revolving Credit Facility was increased by the lending participants to $100.0 million. At December 31, 2013, we did not have any balance outstanding under our New Revolving Credit Facility, compared to our December 31, 2012 outstanding balance of $98.0 million under our revolving credit facility. Borrowing base redeterminations are scheduled semi-annually with the next redetermination scheduled for May 2014. However, we and the lenders may each request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. Borrowings under the Revolving Credit Facility bear interest, at our election, at the reference rate or the Eurodollar rate plus an applicable margin. Pursuant to the Revolving Credit Facility, the reference rate is the greater of (i) the rate of interest publicly announced by the administrative agent, (ii) the federal funds rate plus 50 basis points, or (iii) a LIBOR rate. The applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the reference rate and from 2.0% to 3.0% in the case of borrowings based on the LIBOR 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, as adjusted.
At December 31, 2013, we were in compliance with all financial covenants under the Revolving Credit Facility. For a more detailed description of the terms of our Revolving Credit Facility, see Note 4, "Long Term Debt – Second Amended and Restated Revolving Credit Facility" of this Form 10-K.
Senior Secured Notes. During 2013, we issued $325.0 million aggregate principal amount of 8 5/8% Senior Secured Notes due 2018 in private placements under an indenture. The Notes bear interest at a rate of 8.625% per year, payable semiannually in arrears on May 15 and November 15 of each year, beginning on November 15, 2013. The Notes will mature on May 15, 2018. For a more detailed description of the terms of our Notes, see Note 4, "Long-Term Debt - Senior Secured Notes" of this Form 10-K. At December 31, 2013, we were in compliance with all covenants under the indenture governing the Notes.
Series B Preferred Stock. On November 7, 2013, we issued 2,140,000 shares of 10.75% Series B Preferred Stock at the stated par value of $25.00 per share for net proceeds of $50.1 million. The net proceeds from the issuance of the Series B Preferred Stock were used to partially fund the WEHLU Acquisition, which closed on November 15, 2013. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at December 31, 2013, our stated preferred dividend expense is estimated to be $3.5 million per quarter, subject to being declared and paid monthly.
Parent Guarantees. On December 18, 2013, Parent entered into a parent guarantee agreement (the "Credit Facility Guaranty") to guarantee Gastar USA's obligations under the Revolving Credit Facility. Pursuant to the Credit Facility Guaranty, Parent irrevocably and unconditionally guaranteed the punctual payment and performance of all obligations under the Revolving Credit Facility, subject to fraudulent transfer laws, in the manner and to the extent set forth in the Credit Facility Guaranty. On December 23, 2013, Parent entered into the Parent Guarantee Agreement (the "Notes Guarantee"), pursuant to which Parent jointly and severally, unconditionally guaranteed all notes issued under the indenture governing the Notes. The Credit Facility Guaranty and the Notes Guarantee ceased to be of any force and effect by operation of law as a result of the merger of Parent into Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) on January 31, 2014.

Off-Balance Sheet Arrangements

As of December 31, 2013, we had no off-balance sheet arrangements. We have no plans to enter into any off balance sheet arrangements in the foreseeable future.

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Contractual Obligations

The following table summarizes our future contractual obligations as of December 31, 2013:

	Payments Due by Period						
	Total	2014	2015	2016	2017	2018	Thereafter
	(in thousands)						
Long-term debt (1)	$325,000	$—	$—	$—	$—	$325,000	$—
Interest on long-term debt (2)	122,636	28,031	28,031	28,031	28,031	10,512	—
Deferred put premiums (3)	7,145	145	2,298	2,408	1,460	834	—
Office space leases (4)	1,934	642	593	445	137	117	—
Office equipment leases	61	39	9	8	5	—	—
Drilling rigs	460	460	—	—	—	—	—
Total contractual obligations	$457,236	$29,317	$30,931	$30,892	$29,633	$336,463	$—

(1) See Item 8. “Financial Statements and Supplementary Data, Note 4, Long-Term Debt”, to our consolidated financial statements included in this Form 10-K for a discussion of the Notes.

(2) Interest payments have been calculated by applying the weighted average interest rate of 8.625% at December 31, 2013 to the outstanding long-term debt of $325.0 million at December 31, 2013.

(3) In conjunction with certain crude commodity derivatives contracts, we deferred the payment of certain put premiums for the period January 2014 to August 2018. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

(4) Our Houston office lease obligation expires August 31, 2016, our West Virginia office lease expires on December 31, 2014 and our Oklahoma office lease expires on October 31, 2018.

We maintain a liability for costs associated with the retirement of tangible long-lived assets. At December 31, 2013, our reserve for these obligations totaled $6.1 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

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 and SEI will purchase all hydrocarbon production. All natural gas is transported and processed at the William's 520.0 MMcf/d Fort Beeler processing plant located in Marshall County, West Virginia. 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.

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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 oil and natural gas operations, whereby all costs incurred in the acquisition, exploration and development of oil and natural gas 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 2013, the key benchmark base prices utilized were the Henry Hub price of $3.67 per MMBtu for natural gas and a WTI spot price of $96.78 per barrel of oil. In applying the full cost method at December 31, 2013 and 2011, we performed a ceiling test on the cost center properties whereby the net cost of oil and natural gas 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 oil and natural gas 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, 2013 and 2011. 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. We recorded a ceiling impairment of $150.8 million for the year ended December 31, 2012. 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, 2013 would have reduced our ceiling impairment cushion by approximately $69.2 million resulting in no impairment. A 10% increase in prices at December 31, 2013 would have increased our ceiling impairment cushion by approximately $67.5 million.

Oil and Natural Gas Reserves

All of the reserves data in this Form 10-K are estimates. Estimates of our oil and natural gas reserves were prepared in accordance with guidelines established by the SEC. Our estimate of proved reserves is based on the quantities of oil and natural gas 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 oil and natural gas 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, 2013 reserves estimates on a 12-month unweighted average of the first-day-of-the month prices, in accordance with SEC rules. However, oil and natural gas 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

The units-of-production method is used to amortize our oil and natural gas 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, 2013 by approximately $971,000, while a 10% decrease in reserves would have increased our depletion expense by approximately $1.2 million.

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, 2013, we had $96.2 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 $9.0 million, respectively, for the year ended December 31, 2013.

Asset Retirement Obligation

We have certain obligations to remove tangible equipment and restore land at the end of oil and natural gas 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 oil and natural gas 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 Notes. 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 $3.3 million, $1.9 million and $818,000 for 2013, 2012 and 2011, respectively.

Stock-Based Compensation

We report compensation expense for restricted common stock, performance based units ("PBUs") and stock options 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 restricted common stock granted is equal to the closing price on the day prior to the grant. The fair value of each PBU grant is estimated on the date of grant using the Monte Carlo simulation valuation model. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes-Merton valuation pricing model. 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 Monte Carlo simulation valuation model re quires a variety of inputs, including expected future stock price based on predictive assumptions of volatility, risk free rate, random numbers, the current stock price and forecast period. If any of the assumptions used in the Monte Carlo simulation valuation model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

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, 2013.

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 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.

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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 large financial institutions, to manage market risks resulting from fluctuations in commodity prices of oil, condensate, natural gas 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:

Income taxes. In July 2013, the FASB issued an amendment to previously issued guidance regarding the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The amendment requires that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward, except as follows. To the extent a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The assessment of whether a deferred tax asset is available is based on the unrecognized tax benefit and deferred tax asset that exist at the reporting date and should be made presuming disallowance of the tax position at the reporting date. This amendment does not require new recurring disclosures. This guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Earlier application is permitted. We are currently evaluating the provisions of this amendment and believe that the adoption of such will not have an impact on our operating results, financial position or cash flows.

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, 2013, 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 probable future fluctuations.

Commodity Price Risk

Our major commodity price risk exposure is to the prices received for our oil, condensate, natural gas 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 oil, condensate, natural gas and NGLs in the region produced. Prices received for oil, condensate, natural gas 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 oil, condensate, natural gas and NGLs, we have entered into, and may in the future enter into additional, commodity price risk management arrangements for a portion of our oil, condensate, natural gas and NGLs production. For the year ended December 31, 2013, a 10% change in the prices

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received for our oil, condensate, natural gas and NGLs production would have had an approximate $9.3 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. See Note 7, "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, 2013, we had no borrowings outstanding under our Revolving Credit Facility. We have not entered into interest rate hedging arrangements in the past, and have no current plans to do so. Due to the potential for 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, 2013 at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting of Gastar Exploration, Inc.

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, 2013 based on criteria established in Internal Control—Integrated Framework (1992) 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, 2013 based on the criteria listed herein. The results of management's assessment were reviewed with the Audit Committee of our Board of Directors.

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BDO USA, LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Form 10-K, has issued an attestation report on Gastar Exploration, Inc.'s internal control over financial reporting. Their report appears below.

GASTAR EXPLORATION INC.,
in its capacity as the successor issuer of Gastar Exploration, Inc.

/s/ J. RUSSELL PORTER	/s/ MICHAEL A. GERLICH
J. Russell Porter	Michael A. Gerlich
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer
March 13, 2014	March 13, 2014

Management's Report on Internal Control over Financial Reporting of Gastar Exploration Inc.

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, 2013 based on criteria established in Internal Control—Integrated Framework (1992) 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, 2013 based on the criteria listed herein. The results of management's assessment were reviewed with the Audit Committee of our Board of Directors.

Gastar Exploration Inc. is not required to have, nor have we engaged anyone to perform, an audit of its internal control over financial reporting.

GASTAR EXPLORATION INC.

/s/ J. RUSSELL PORTER	/s/ MICHAEL A. GERLICH
J. Russell Porter	Michael A. Gerlich
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Corporate Secretary
March 13, 2014	March 13, 2014

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2013, 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.

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gastar Exploration, Inc.
Houston, Texas

We have audited Gastar Exploration, Inc.'s (the "Company") internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework (1992) 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

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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, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, 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, Inc. and its subsidiaries as of December 31, 2013 and 2012 and the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2013 and our report dated March 13, 2014 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
March 13, 2014

Item 9B. Other Information

Settlement Agreement

On March 12, 2014, we entered into a settlement agreement (the “Settlement Agreement”) with Kleinheinz Capital Partners, Inc., Global Undervalued Securities Master Fund, L.P., John B. Kleinheinz and Fred N. Reynolds (collectively, the “Kleinheinz Group”).

The Settlement Agreement provides that we will expand our board of directors (the “Board”) from five to seven members and appoint two directors agreeable to both us and the Kleinheinz Group (the “Mutually Agreed Directors”). Under the Settlement Agreement, our Nominating and Governance Committee will engage an executive search firm to identify two candidates who are unaffiliated with us and the Kleinheinz Group, qualify as independent under rules of the SEC and the NYSE and have experience and qualifications set forth in the Settlement Agreement.

Under the terms of the Settlement Agreement, we agreed to nominate the Mutually Agreed Directors for election as directors to the Board at the 2014 Annual Meeting (to the extent such Mutually Agreed Directors have been selected, approved and appointed prior to the mailing of the definitive proxy statement for the 2014 Annual Meeting) and the 2015 Annual Meeting of stockholders and to recommend that our stockholders vote in favor of the election of the Mutually Agreed Directors at both meetings.

The Settlement Agreement includes customary standstill provisions, subject to certain exceptions. The Kleinheinz Group agreed to not disclose confidential information obtained in connection with the search process. The parties agreed to mutual covenants not to sue. Each party further agreed not to publicly disparage the other party outside of otherwise required legal processes.

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The Settlement Agreement will terminate, subject to certain exceptions, 60 days prior to the expiration of the Company's advance notice period for the nomination of directors and submission of stockholder proposals for the 2016 Annual Meeting of stockholders.

A copy of the Settlement Agreement is attached as Exhibit 10.30 to this Annual Report on Form 10-K and incorporated by reference herein and is hereby filed. The foregoing description of the Settlement Agreement is qualified in its entirety by reference to the full text of the Settlement Agreement.

Employee Change of Control Severance Plan

On March 12, 2014, the board of directors of Gastar Exploration Inc. approved the adoption of the second amendment to the Gastar Exploration Ltd. Employee Change of Control Severance Plan (the "COC Severance Plan Amendment"), effective retroactively to March 1, 2014, to the Gastar Exploration Ltd. Employee Change of Control Severance Plan, as previously amended and restated on February 15, 2008, and amended on April 11, 2012 (the "Plan"). The COC Severance Plan Amendment modifies the target bonus component of the change of control severance payment formula under the Plan to reflect previous increases in target annual bonuses and establishes the change of control severance payment formula for the position of Chief Operating Officer. Pursuant to the COC Severance Plan Amendment, the target bonus component of the change of control severance payment formula under the Plan is increased to 89% for the Company's Chief Executive Officer (from 75%), 88% for the Company's Chief Financial Officer (from 60%), 65% for the Company's vice presidents (from 25%) and 30% for the Company's directors (from 25%). In addition, the COC Severance Plan Amendment establishes a severance period under the Plan of 2.5 years and a target bonus component of the change of control severance of 88% for the Company's chief operating officer. The COC Severance Plan Amendment renames the plan as the "Gastar Exploration Inc. Employee Change of Control Severance Plan" also makes certain other changes to reflect the assumption of the COC Severance Plan by Gastar Exploration Inc. in connection with the merger of Gastar Parent and Gastar USA.

A copy of the COC Severance Plan Amendment is attached as Exhibit 10.27 to this Annual Report and incorporated by reference herein and is hereby filed. The foregoing description of the COC Severance Plan Amendment is qualified in its entirety by reference to the full text of the COC Severance Plan Amendment.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Directors and Executive Officers

Our executive officers, other members of management and directors, and their ages and positions as of March 1, 2013, are as follows:

Name	Age	Position
J. Russell Porter (1)	52	President and Chief Executive Officer
Michael A. Gerlich (1)	59	Senior Vice President, Chief Financial Officer and Corporate Secretary
Michael McCown (1)	59	Senior Vice President and Chief Operating Officer
Keith R. Blair	59	Vice President and Exploration Manager
Henry J. Hansen	58	Vice President - Land
John M. Selser Sr.	55	Chairman of the Board
John H. Cassels	66	Director
Randolph C. Coley	67	Director
Robert D. Penner	70	Director

(1) Messrs. Porter, Gerlich and McCown are our only "Executive Officers" as such term is defined by the rules promulgated by the SEC.

Set forth below is biographical information about each of the executive officers and directors named above.

J. Russell Porter has been a member of the Board and has served as our President and Chief Executive Officer since February 2004. From August 2006 until January 2010, he also served as Chairman of the Board. From September 2000 to February 2004, he served as our Chief Operating Officer. Mr. Porter has an energy focused background, with approximately 22

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years of natural gas and oil exploration and production experience and five years of banking and investment experience specializing in the energy sector. From April 1994 to September 2000, Mr. Porter served as an Executive Vice President of Forcenergy, Inc., a publicly-traded exploration and production company, where he was responsible for the acquisition and financing of the majority of its assets across the United States and Australia. He currently is a director of Caza Oil & Gas, Inc., a publicly-traded exploration and development company listed on the Toronto Stock Exchange and the London AIM exchange. He has held no other directorship positions in publicly-traded companies during the last five years. Mr. Porter holds a Bachelor of Science degree in Petroleum Land Management from Louisiana State University and a MBA from the Kenan-Flagler School of Business at the University of North Carolina at Chapel Hill. Mr. Porter was chosen as a director nominee because he is our Chief Executive Officer and has proven management skills. He has extensive knowledge of the natural gas and oil industry and experience in managing natural gas and oil assets as well as relationships with chief executives and other senior management of natural gas and oil companies and oilfield service companies throughout the United States. Mr. Porter actively participates in all facets of our business and has a significant influence on both its business strategy and daily operations. Mr. Porter resides in Houston, Texas, USA.

Michael A. Gerlich joined us in May 2005 as Vice President and Chief Financial Officer and was appointed Corporate Secretary on March 8, 2011. Mr. Gerlich has over 34 years of natural gas and oil accounting and finance experience. From 1999 until joining us in 2005, he held various accounting and finance positions at Calpine Natural Gas LP, a wholly-owned subsidiary of Calpine Corporation, an independent electric power generation company listed on the New York Stock Exchange. His last position at Calpine Natural Gas LP was Senior Vice President – Accounting and Finance for natural gas and oil operations of the wholly-owned subsidiary. From 1994 until 1999, Mr. Gerlich served as Vice President and Chief Financial Officer of Sheridan Energy, Inc., an independent natural gas and oil exploration company traded on the NASDAQ, which was acquired in 1999 by Calpine Corporation. Over a 12-year period prior to joining Sheridan Energy, Inc., Mr. Gerlich held various accounting and finance positions with Trinity Resources, Ltd., an independent natural gas and oil exploration and production company, with his last position being Executive Vice President and Chief Financial Officer. Prior to that, Mr. Gerlich was also with Deloitte LLP, where the focus of his practice was with energy related clients. Mr. Gerlich has been a member of the board of directors and served as the Audit Committee Chairman for Petropoint Energy Partners LP, a private upstream oil and gas limited partnership, since November 2012. Mr. Gerlich is a Certified Public Accountant and graduated with honors from Texas A&M University with a Bachelor of Business Administration degree in Accounting.

Michael McCown joined us in December 2009 as a Senior Advisor and in June 2013, was elected Senior Vice President and Chief Operating Officer, having previously served as our Vice President – Northeast since July 2010. Prior to joining us, from 2006 to June 2010, Mr. McCown held various positions with CDX Gas LLC, predecessor to Vitruvian Exploration LLC, including Chief Operating Officer and Senior Vice President & General Manager. From 2004 to 2006, Mr. McCown was with EOG Resources Inc. as Operations Manager. He has over 37 years experience in production, drilling and operations throughout the United States including the Unitah, Permian and Appalachian Basins. Other experience includes managerial responsibilities for companies including Pennzoil Company, Devon Energy Corp. and East Resources. Mr. McCown has served two terms on the Board of WV Oil and Natural Gas Association and is a former President of that association. He is currently serving his second term on the Board of the Independent Oil and Gas Association of West Virginia and he served as President of the association from August 2010 through August 2011. Mr. McCown holds a Bachelor of Science degree in Civil Engineering from Ohio University and is a Registered Professional Petroleum Engineer.

Keith R. Blair joined us in August 2005 as a Senior Staff Geologist and was promoted to Vice President, Exploration Manager in 2008. Mr. Blair has over 34 years of natural gas and oil experience. He has extensive working knowledge of natural gas and oil basins in Colorado, New Mexico, East Texas, West Virginia/Pennsylvania, Offshore Gulf of Mexico and the Texas/Louisiana Gulf Coast. Prior to joining us, from 1999 until 2005, he was an independent exploration geologist. From 1995 until 1999, Mr. Blair was a Senior Geophysicist at Schlumberger Limited. Prior to 1995, he held an Exploration Manager/Supervisor position at ConocoPhillips for 14 years. He began his career as a well logging engineer with Halliburton Company. Mr. Blair graduated from Texas A&M University with a Bachelor of Science degree in Geology.

Henry J. Hansen joined us in September 2005 as Vice President of Land. Mr. Hansen has over 34 years of land management experience. Prior to joining us, Mr. Hansen was Rocky Mountain Land Manager with El Paso Corporation, a natural gas and oil exploration, production and pipeline company, from 1999 until January 2003. From January 2003 until June 2004, he worked as an independent land consultant. Mr. Hansen returned to El Paso Corporation in June 2004, where he was a senior landman until joining us in September 2005. Mr. Hansen graduated from the University of Texas at Austin with a Bachelor of Business Administration in Petroleum Management.

John M. Selser Sr. became a member of the Board effective March 30, 2007 and effective January 4, 2013, was appointed Chairman of the Board. Currently, Mr. Selser is portfolio manager of Tightline Capital LLC, an equity hedge fund and also serves on the board of directors of Our Lady of the Lake Hospital in Baton Rouge and the investment committee of the Franciscan Ministries of Our Lady, the parent corporation of Our Lady of the Lake. From 2010 to 2012, Mr. Selser was a managing director of energy research at IBERIA Capital Partners LLC, a subsidiary of IBERIA Bank Corporation. Also in

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2010, he was an instructor of finance at Louisiana State University. From 2003 to 2009, he was a partner at Maple Leaf Partners, a long short equity hedge fund. From 1992 to 2003, he was an energy equity analyst for several sell-side firms including Lehman Brothers, Howard Weil and Johnson Rice. From 1984 to 1992, Mr. Selser was a petroleum engineer for Chevron and Mobil in various domestic drilling, production and reservoir engineering assignments. He has held no directorship positions in publicly-traded companies during the last five years other than that of Gastar. Mr. Selser holds a Bachelor of Science in both Civil Engineering and Petroleum Engineering from Louisiana State University, Baton Rouge, Louisiana and a Masters of Business Administration from Tulane University, New Orleans, Louisiana. Mr. Selser was chosen as a director because of his significant finance experience as well as his prior engineering and exploration and production experience, which provides a meaningful perspective in the Board's oversight of Gastar's execution of its long-term business strategy.

John H. Cassels was elected to the Board effective March 8, 2011. Mr. Cassels is a Chartered Accountant with 37 years of direct experience in the Canadian oil and natural gas industry, having been a senior officer and director of ten junior oil and natural gas companies. On July 1, 2011, he was appointed to the position of Vice President, Chief Financial Officer and Secretary of Cascade Resources Inc., a private junior oil and gas exploration company based in Calgary, Alberta. On December 15, 2011, Cascade Resources Inc. was amalgamated with Northern Spirit Resources Inc., a publicly traded oil and natural gas company listed on the Toronto Stock Exchange. Prior to that appointment, he served as a partner and Chief Financial Officer of Purdy Partners Inc., a private equity/merchant bank in Calgary, Alberta, a position he held from December 2009 to July 2011. From September 2008 until November 2009, Mr. Cassels was a financial consultant to a Canadian oil and gas exploration company operating in both Argentina and Canada. From 2007 through September 2008, he served as a Director of World Cup Operations/Alpine Canada, which organized Alpine test events for the 2010 Olympic Winter Games in Vancouver. From 2003 through 2007, he was a founding shareholder, Chief Executive Officer and director of Highview Resources, a publicly-traded company that built a significant inventory of oil and natural gas prospects in Alberta and Saskatchewan. Mr. Cassels holds a Bachelor of Arts degree from Bishop's University in Sherbrooke, Québec. Mr. Cassels resides in Calgary, Alberta, Canada. Mr. Cassels was chosen as a director because of his valuable financial expertise and extensive knowledge of the oil and gas industry. His business and management expertise from his position as an executive officer and director of many companies also provides the Board with important perspectives on key corporate governance matters.

Randolph C. Coley was appointed to the Board in January 2010. Mr. Coley is currently retired and has been since the end of 2008. From 1999 until his retirement at the end of 2008, Mr. Coley was a partner in the Houston, Texas office of the law firm of King & Spalding LLP, where his practice was concentrated in the areas of corporate and securities law. Previously, he served as Executive Managing Director and Head of Investment Banking for Morgan Keegan & Company, Inc. and was a partner in King & Spalding LLP's Atlanta office. He is a director of Deltic Timber Corporation, a publicly-traded natural resources company engaged primarily in the growing and harvesting of timber and the manufacture and marketing of lumber, a position he has held since 2007. Additionally, he is a member of the audit and the nominating and corporate governance committees of that organization. He is also a director of Trade Street Residential, Inc. (“Trade Street”), a real estate investment trust that develops and owns residential apartments. Mr. Coley is a member of the audit committee and chairs the nominating and corporate governance committee of Trade Street. He has held no other directorship positions in publicly-traded companies during the last five years. Mr. Coley earned his undergraduate degree from Vanderbilt University and graduated with a law degree from Vanderbilt School of Law. Mr. Coley resides in Atlanta, Georgia, USA. Mr. Coley was chosen as a director nominee because of his extensive business and legal background and his keen understanding of various corporate governance matters that he has attained through his representation of and service on other public company boards.

Robert D. Penner became a member of the Board effective July 2007. Mr. Penner currently is and has been an independent consultant since 2004, when he retired from his position as a senior partner with KPMG, after a career of advising public and private clients on tax and accounting matters for almost 41 years. He currently serves on the board of directors for Equana Technologies Inc. (formerly Sustainable Energy Technologies Ltd.), a manufacturer and seller of electronic components for grid-connected solar power systems as well as Corridor Resources Ltd., and Terra Energy Corp., each involved in the exploration, development and production of natural gas and oil. On April 20, 2010, Mr. Penner resigned from the board of directors of Altima Resources Ltd. (successor company to Unbridled Energy

Corporation). On September 29, 2011 Mr. Penner resigned from the Board of Storm Cat Energy Corporation. He additionally serves on the board of directors or as executor/trustee for several private companies and family trusts. Mr. Penner received his Chartered Accountant designation in 1971 in Manitoba and 1977 in Alberta. He has held no other directorship positions in publicly-traded companies during the last five years. Mr. Penner is currently the audit committee chairman for each of the public companies of which he is a director and serves on the compensation and governance committees of Terra Energy Corp. and Corridor Resources Inc. Mr. Penner resides in Calgary, Alberta, Canada. Mr. Penner was chosen as a director nominee because of his keen understanding of finance, accounting and various corporate governance matters that he has attained through his career with KPMG and service on other public company boards.

There are no family relationships between our Named Executive officers, those members of management noted above and our directors.

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Cease Trade Orders

Except as disclosed below, to the knowledge of our management, none of our directors or executive officers is, or within the 10 years before the date of this filing has been a director, chief executive officer or chief financial officer of any company (including us) that:

(a) Was the subject of a cease trade or similar order or an order that denied the other issuer access to any exemptions under securities legislation that lasted for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as a director, chief executive officer or chief financial officer; or

(b) Was subject to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation that lasted for a period of more than 30 consecutive days that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer.

Mr. Penner served as a director of Storm Cat Energy Corporation (“Storm Cat”), a position he held from January 2005 through September 2011. In November 2008, the U.S. subsidiaries of Storm Cat filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code, and Storm Cat was subsequently delisted from the Toronto Stock Exchange and the NYSE Amex LLC (the “NYSE Amex”), which delistings remain in effect as of the date hereof. In April 2009, pursuant to an order of the Ontario Securities Commission, the Securities of Storm Cat were “cease traded” for a failure to file audited annual financial statements, management's discussion and analysis and an annual information form, all for the year ended December 31, 2008, and such order remains in effect as of the date hereof.

Bankruptcies

Except as set forth below or as disclosed above under subheading “Cease Trade Orders,” to the knowledge of our management, none of our directors or executive officers:

(a) Is, at the date of this filing or has been within the 10 years before the date of this filing, a director or executive officer of any company (including us) that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) Has, within the 10 years before the date of this filing, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director nominee.

Mr. McCown served as an officer of CDX Gas LLC from 2006 to 2010. In December 2008, while Mr. McCown was serving as a Senior Vice President, CDX Gas LLC and certain of its subsidiaries filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Mr. McCown was promoted to Executive Vice President and Chief Operating Officer on January 22, 2009 where he served during the company's restructuring. Mr. McCown remained in this position until the restructured company emerged as Vitruvian Exploration, LLC and he was reassigned as Senior Operations Consultant.

Penalties or Sanctions

To the knowledge of our management, none of our directors or executive officers:

(a) Has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with the securities regulatory authority; or

(b) Has been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable shareholder in deciding whether to vote for a director nominee.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors and persons who own more than 10% of our common shares to file reports of ownership and changes in ownership with the SEC. These persons are required by SEC regulations to furnish us with copies of all Section 16(a) reports that they file.

To our knowledge, based on our review of the copies of such reports and written representations that no other reports were required, we believe that all such filing requirements were complied with during the fiscal year ended December 31, 2013; except a Form 4 filing for Mr. Cassels made on February 12, 2013, which was 13 days late due to an administrative oversight, and a Form 4 filing for Mr. Penner made on February 12, 2013, which was 13 days late due to an administrative oversight.

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Governance Practices
The Board believes that good corporate governance improves corporate performance and benefits all shareholders.
Code of Ethics
Parent adopted a Code of Conduct and Ethics for all employees, including our executive officers, on December 15, 2005, which was amended and restated on March 22, 2011. In connection with the merger, on January 31, 2014, Gastar USA adopted a Code of Conduct and Ethics for all employees, including our executive officers. A copy of the Code of Conduct and Ethics is available at http:www.gastar.com, and you may also request a copy of the Code of Conduct and Ethics at no cost, by writing or by telephoning us at the following: Gastar Exploration Inc., 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 Conduct and Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Chief Operating Officer and persons performing similar functions on our website at http://www.gastar.com promptly following the date of any such amendment or waiver.
Audit Committee
The Board has designated a standing Audit Committee. The Audit Committee currently consists of Messrs. Penner (Chairman), Coley and Selser, each of whom the Board has determined to be independent under the rules of the NYSE MKT LLC and Section 10A ("Audit Requirements") of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The Board has determined that each member of the Audit Committee is financially literate and Mr. Penner is an "audit committee financial expert," within the meaning proscribed by the rules and regulations promulgated by the SEC. He became a member of the Board effective July 16, 2007. Mr. Penner is a retired senior partner with KPMG LLP, whose career of advising public and private clients on tax and accounting matters has spanned almost 41 years.
In accordance with its charter, the Audit Committee examines and reviews, on behalf of the Board, internal financial controls, financial and accounting policies and practices, the form and content of financial reports and statements and the work of the external auditors. The Audit Committee is responsible for hiring, overseeing and terminating the independent registered public accounting firm and determining the compensation of such accountants. The Chief Financial Officer attends the meetings of the Audit Committee by invitation.
The Audit Committee assists the Board in overseeing matters relating to our accounting and financial reporting practices, the adequacy of its internal controls and the quality and integrity of its financial statements, and is responsible for selecting and retaining the independent auditors. The Audit Committee's responsibilities are more fully described in its charter. Our management is responsible for preparing our financial statements, and the independent auditors are responsible for auditing those financial statements. The Audit Committee does not provide any expert or special assurance as to our financial statements or any professional certification as to the independent auditors' work.
A copy of the charter for the Audit Committee is available free of charge on our website at www.gastar.com. A copy of the charter will also be provided to any person without charge, upon request. Such requests should be directed to our Secretary at 1331 Lamar Street, Suite 650, Houston, Texas 77010.
Item 11. Executive Compensation
Compensation Discussion & Analysis
This Compensation Discussion and Analysis provides information regarding the compensation paid to J. Russell Porter, our President and Chief Executive Officer ("CEO"), paid to Michael A. Gerlich, our Senior Vice President and Chief Financial Officer ("CFO") and paid to Michael McCown, our Senior Vice President and Chief Operating Officer ("COO"). On June 7, 2013, Mr. Gerlich was promoted to Senior Vice-President from Vice-President and Mr. McCown was promoted to Senior Vice-President and Chief Operating Officer from Vice-President Northeast Operations. These individuals are referred to as "Named Executive Officers." Messrs. Porter, Gerlich and McCown are our only Named Executive Officers as they were our only "Executive Officers," as such term is defined by the rules promulgated by the SEC, during 2013.
As described above, pursuant to the merger agreement, shares of the Parent's common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to "Gastar Exploration Inc." Following the closing of the merger transaction, compensation decisions previously made by Parent's Compensation Committee will be made by the compensation committee of Gastar Exploration Inc. (which is comprised of the same members as constituted Parent's compensation committee during 2013). References in this Compensation Discussion

& Analysis to the “Board” or the “Compensation Committee” constitute references to the Compensation Committee of Parent with respect to actions taken prior to the merger, and constitute references to the Board or Compensation Committee of Gastar Exploration Inc. respectively, with respect to actions taken after the merger.

Compensation Philosophy and Objectives

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Our executive compensation program is designed to provide compensation at a level necessary to retain talented and experienced executives and to motivate them to achieve both short-term and long-term corporate goals that enhance shareholder value. Consistent with this philosophy, the following are the key objectives of our compensation programs.

Attract, Motivate and Retain Key Employees. Our executive compensation program is shaped by the competitive market for management talent in the independent natural gas and oil exploration and production industry. We believe our executive compensation should be comparable to that of the companies with which we compete for talent. Our goal is to provide compensation and benefits at levels that attract, motivate and retain superior executive talent for the long-term.

Shareholder Interest Alignment. One of the objectives of our executive compensation program is to ensure that an appropriate relationship exists between executive pay, our financial performance and the creation of shareholder value. We believe that linking executive compensation to corporate performance results in a better alignment of compensation with corporate goals and shareholder interests. Our compensation program aligns pay to performance by making a substantial portion of total executive compensation variable, or “at-risk,” through an annual bonus program based on our performance goals and the granting of long-term incentive equity awards, which have included restricted common shares and stock options. As performance goals are met, not met or exceeded, executives are rewarded commensurately.

Determination of Executive Compensation

Role of the Compensation Committee. Executive compensation is the responsibility of the Compensation Committee. The Compensation Committee operates under a written charter adopted by the Board. John H. Cassels, Randolph C. Coley and John M. Selser Sr. are members of the Board and the current members of the Compensation Committee. Mr. Cassels is the current Compensation Committee Chairman. Each member of the Compensation Committee qualifies as an independent director under the NYSE MKT LLC listing standards and under the Exchange Act. A copy of the Compensation Committee’s charter is available to shareholders on our website at www.gastar.com.

Philosophy of the Compensation Committee. The Compensation Committee’s philosophy is strongly driven by a “Pay for Performance” compensation approach that focuses on enhancing shareholder value. The Compensation Committee presently targets total compensation, which consists of base salary, annual incentive awards and long-term stock awards at the 50th percentile of its peer group as defined by an independent third party compensation consultant. If management’s efforts cause the Company’s results to materially exceed or lag behind the results of its peer group, total compensation may be adjusted upward or downward from the 50th percentile. The Compensation Committee believes that this approach awards and compensates our Named Executive Officers in a manner that fairly provides incentives for the enhancement of shareholder value, for the successful implementation of our business plan and the continuous improvement in corporate and personal performance.

During 2013, the Compensation Committee reviewed the cash compensation, performance and overall compensation package for each Named Executive Officer. It then submitted to the Board recommendations with respect to the salary, bonus and participation in equity-based compensation arrangements for each Named Executive Officer. In conducting its review of management’s recommendations, the Compensation Committee was satisfied that all recommendations complied with the Compensation Committee’s philosophy and guidelines.

Interaction Between the Compensation Committee and Management. Our CEO plays an important role in the executive compensation process and is closely involved in assessing the performance of our CFO and COO, who are our other Named Executive Officers. He also makes recommendations to the Compensation Committee regarding base salary, bonus targets, and performance goals established for the annual incentive plan, as well as weighting and equity compensation for our CFO and COO. Our CEO’s recommendations are based on his review of any market or peer group analysis data provided by our compensation consultant, an assessment of our CFO and COO’s responsibilities and performance, our performance and the compensation that companies in our peer group pay their executives in comparable positions. Our CFO also plays an important role in our executive compensation process. He makes recommendations to the Compensation Committee regarding the structure of the annual cash bonus awards program and the target size of such awards. These recommendations are drawn from his previous work experience, informal discussions with other CFOs and review of publicly filed information of other similarly-sized natural gas and

oil companies regarding their bonus programs.
Role of Consultant and Market Analysis. For 2013 the Compensation Committee utilized 2012 data supplied by Longnecker & Associates ("L&A"). For the purposes of its report, L&A's engagement objectives in 2012 included:

- Review total direct compensation (base salary, annual incentives and long-term incentives) for the Named Executive Officers;
- Assess the market competitiveness of executive compensation as compared to our peer group and published surveys of other companies in the oil and natural gas industry with revenues and capital assets comparable to our revenue and capital assets; and

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- Provide conclusions and recommendations for current total direct compensation packages for our Named Executive Officers.

L&A's approach to this study was based upon its experience in the design of executive compensation programs in the energy industry and external market data procured from the marketplace in which we compete for top-level talent. This experience, along with its competitive market analysis, allowed L&A to make compensation recommendations that provide us with information to attract, retain, and motivate top-level executive talent. Additionally, L&A's recommendations were tailored to balance external market data and our internal environment to ensure fiscal responsibility.

Specifically, L&A's approach was to gather compensation data from (a) public peer companies and (b) published salary surveys and to conduct a market comparison analysis of the gathered data. Prior to beginning its analysis, L&A reviewed the composition of our peer group to assess the continued appropriateness of the group and ensure that the included companies were still relevant for comparative purposes. Based on its review, L&A recommended that companies that had been acquired or delisted, as well as companies whose geographic scope and nature of operations differed from ours be removed. L&A also expanded the number of companies included in our peer group, which was comprised of companies with a similar production profile, revenue base and size, as measured by market capitalization. The updated peer group was approved by the Compensation Committee as representative of the sector in which we operate. Next, L&A analyzed current total direct compensation (base salary, plus annual incentive, plus long-term incentive), as compared to the updated peer group and published survey data based on industry, size and performance. This was followed by developing conclusions and recommendations, which was reported to the Compensation Committee.

Companies reviewed by L&A (the "Peer Group") included:

Abraxas Petroleum Corp.
Approach Resources, Inc.
Bonannza Creek Energy, Inc.
Callon Petroleum Company
Carrizo Oil & Gas Inc.
Crimson Exploration Inc.
Diamondback Energy, Inc.
Goodrich Petroleum Corp.
Magnum Hunter Resources Corp.
Panhandle Oil and Gas Inc.
PetroQuest Energy Inc.
Rex Energy Corporation
Triangle Petroleum Corporation
Vanguard Natural Resources, LLC
Warren Resources Inc.

Based upon 2012 comparative pay information of our peer group developed by L&A and published survey data, the Compensation Committee determined that the Named Executive Officers' (a) 2013 base salaries were 5% above the 50th percentile of our Peer Group for the CEO and 2% and 14% below the 50th percentile of our Peer Group for the CFO and COO, respectively, (b) 2013 total cash compensation (base salary, plus the annual cash incentive award) were approximately 4% above the 50th percentile of our Peer Group for the CEO and 8% and 20% below the 50th percentile of our Peer Group for the CFO and COO, respectively, (c) 2013 long-term equity awards were 18% and 58% below the 50th percentile of our Peer Group for the CEO and COO, respectively, and 19% above the 50th percentile of our Peer Group for the CFO, and (d) 2013 total direct compensation (base salary, plus the annual cash incentive award, plus equity incentive awards) equaled the 50th percentile of our Peer Group for the CEO and CFO, respectively, and was 30% below the 50th percentile of our Peer Group for the COO. Mr. McCown's compensation components and total compensation lag Peer Group metrics due to his holding the position of COO effective for approximately seven months in 2013. Based upon these findings, the Compensation Committee believes that the individual pay components and total direct compensation levels of the Named Executive Officers in 2013 approximated market levels.

Though we review information regarding the compensation practices of our Peer Group of companies and the survey data just discussed, individual compensation decisions for our CFO and COO are subject to upward or downward adjustment, based on the recommendations of our CEO and a number of factors related to both corporate and individual performance. We use the data regarding the pay practices of companies in our Peer Group as a reference point and as a guide to competitiveness and reasonableness, but we do not adhere to rigid targets, based upon the compensation components of employees at companies within that group. Our present objective is to maintain total direct compensation, consisting of base salary, performance-based cash compensation and equity awards, in proximity to the 50th percentile of our Peer Group. However, the Compensation Committee has the discretion to adjust an award upward or downward to account for individual achievement in the last fiscal year, the requirements of a particular position, and market competitiveness for a particular individual's skills and services, among other factors.

Compensation for Our Named Executive Officers and Rationale

Base Salary. Base salary represents the fixed element of the Named Executive Officers' cash compensation. The base salary reflects results of individual negotiations, economic consideration for each individual's level of responsibility, expertise, skills, knowledge, experience and performance and reasonable comparability of similar executive base salaries for executives employed by companies in our Peer Group. In 2013, the Compensation Committee did not adjust the base salary amounts for Messrs. Porter or Gerlich. Mr. Porter's 2013 base salary exceeds the 50th percentile of our Peer Group by 5% and Mr. Gerlich's 2013 base salary is 2% below the 50th percentile of our Peer Group. In conjunction with his promotion to COO on June 7, 2013, Mr. McCown received a base salary that is below the 50th percentile of our Peer Group by 14%.

Annual Cash Incentive Awards. Our annual cash incentive awards reflect our philosophy to reward performance. These awards provide our Named Executive Officers with an opportunity to earn an annual cash bonus based on pre-established operational and financial performance targets and an evaluation of individual performance. The targeted bonus percentage of our CEO is 75% of his respective base salary and the targeted bonus percentages of our CFO and COO are 60% of their respective base salary amounts. For 2013, the Compensation Committee approved a $725,000 total management target cash bonus pool for our Named Executive Officers, which was based on the sum of each of our Named Executive Officer's "target bonus" opportunity expressed as a percentage of the Named Executive Officer's base salary. The bonus pool is accrued throughout the year, and bonuses are normally paid out early in the following year. For 2013, the annual cash incentive awards for Mr. Porter was 3% above the 50th percentile of our Peer Group, and for Messrs. Gerlich and McCown were 15% and 25% below the 50th percentile of our Peer Group, respectively. The larger awards during 2013 were the result of the Company's strong 2013 operational and financial performance as compared to bonus metrics.

At the beginning of the year, and as part of our budgeting process, specific operational and financial target criteria are established by the Compensation Committee. In developing the appropriate target criteria and their respective weightings, the Compensation Committee analyzes the relative importance of each of the target criteria to our business strategy for the upcoming year. Each criterion is given a certain weighting, with 30% of the 2013 potential bonus opportunity contingent on the achievement of specific operational factors, 20% contingent on the achievement of a specific financial performance factor and 50% contingent on the achievement of additional per share operational targets and a specific market factor. During the year, operational and financial performance is measured against the criteria. Market performance is measured at December 31, 2013. Judgments that the criteria are being met or not being met may lead to an increase in the pool and an adjustment in the bonus accrual. Criteria and weightings used in 2013 were as follows:

Goal	Threshold	Target	Maximum	Actual	Weighting	
Target average annual production (MMcfe/d)	45.4	50.5	55.5	53.7	10	%
Target proved reserves additions (Bcfe)	45.9	51.0	56.0	103.3	10	%
Average finding costs ($/Mcfe)	$2.64	$2.40	$2.16	$1.10	5	%
Average controllable lifting costs ($/Mcfe)	$0.57	$0.51	$0.46	$0.46	5	%
Operating cash flow ($ in millions)	$40.9	$45.5	$50.0	$46.4	20	%
Operating cash flow per share	$0.68	$0.75	$0.83	$0.77	10	%
Production per share (Mcfe)	0.28	0.31	0.34	0.32	20	%
Reserves per share (Mcfe)	4.12	4.57	5.03	5.44	20	%

If threshold targets are not met with respect to a criterion, then the portion of the bonus allocable to that criterion is not paid. At the end of the year, an approved bonus pool is calculated based on the bonus pool criteria accomplishments. The amount of the calculated bonus pool is subject to adjustment and final approval by the Compensation Committee. For 2013, management's bonus pool target was $725,000. As all eight of the target goals were achieved or exceeded, our Named Executive Officers were entitled to receive a combined annual cash incentive payout of $946,130 based on the achieved goals weighted bonus target.

The Compensation Committee's policy is not to award bonuses if performance targets are not met. The Board, however, maintains the ability to award discretionary bonuses if warranted. Pursuant to Mr. Porter's employment agreement, Mr. Porter is guaranteed a bonus equal to 20% of his annual base salary.

The 2014 metrics are expected to be materially similar to those used in 2013.

Long Term Stock-based Compensation. We believe that stock-based compensation is the most effective means of linking compensation provided to our Named Executive Officers with long-term operational success and increases in shareholder value. The Board has discretionary authority to determine granting and vesting periods of stock option, restricted common share and performance based units grants. We use stock-based compensation as a long-term vehicle for compensation because we believe:

- Stock-based compensation aligns the interests of our Named Executive Officers with those of the shareholders by providing equity participation to our Named Executive Officers; and
- The vesting period incorporated into stock-based compensation fosters a longer-term perspective necessary for executive retention, stability and continuity.

Prior to the adopting of the 2006 Plan (as defined below), the only vehicle that was available to us for long-term equity incentives was grants of stock options. After the adoption of the 2006 Plan, grants of restricted common shares and performance based units ("PBUs") became available as incentive vehicles. Based on our determination that our Peer Group and other competitors had shifted the composition of their equity awards to consist primarily of restricted stock awards, starting in 2010 we granted only restricted common share awards. During 2013, based on market research and peer studies, we issued PBUs in addition to restricted stock awards. The Compensation Committee adheres to our policy of only granting stock-based compensation grants during open trading windows. The 2013 grants of restricted common shares and PBUs vest in one-third increments on the first, second and third anniversaries of the grant date, a vesting period that the Compensation Committee believes is an appropriate balance between longer term incentive coupled with an element of shorter term reward. The PBUs represent a contractual right to receive shares of Parent's common stock, an amount of cash equal to the fair market value of a share of Parent's common stock, or a combination of shares of Parent's common stock and cash as of the date of settlement based on the number of PBUs to be settled. The settlement of PBUs may range from 0% to 200% of the targeted number of PBUs stated in the agreement contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PBUs vest equally and settlement is determined annually over a three year period. Any PBUs not vested at each measurement date expire.

In 2013, Messrs. Porter, Gerlich and McCown received restricted common share grants of 484,914 shares, 242,457 shares and 168,103 shares, respectively. In addition to restricted common shares, Messrs. Porter, Gerlich and McCown received PBU grants of 381,983 units, 240,302 units and 133,621 units, respectively. The combined fair values of these grants calculated to be 232%, 219% and 142% of Messrs. Porter, Gerlich and McCown's base salaries, respectively, which placed Messrs. Porter and McCown 18% and 58%, respectively, below the market 50th percentile and placed Mr. Gerlich 19% above the market 50th percentile. The goal of the Compensation Committee has been to move more of the Named Executive Officers' total executive compensation to variable, or "at-risk," and thus further align the interest of the officer with the shareholders by providing the Named Executive Officers a greater stake in our long-term performance. The 2013 restricted stock and PBU grants were consistent with this goal.

Upon vesting on January 30, 2014, the first tranche of PBUs granted on January 30, 2013 to Messrs. Porter, Gerlich and McCown settled at the maximum settlement of 200%.

All Other Compensation. The Named Executive Officers are eligible to participate on a non-discriminatory basis in the same comprehensive benefits as are offered to all full-time employees. These benefits are provided so as to assure that we are able to maintain a competitive position in terms of attracting and retaining executive officers and other employees.

Tax Deductions for Compensation

In conducting our executive compensation programs, the Compensation Committee considers the effects of Section 162(m) of the Internal Revenue Code, as amended (the "Code"), which denies publicly held companies a tax deduction for annual compensation in excess of $1.0 million paid to their chief executive officer or any of their three other most highly compensated executive officers, other than the chief financial officer, who are employed on the last day of a given year, unless their compensation is based on performance criteria that are established by a compensation committee which is made up of outside directors and approved, as to their material terms, by our shareholders. While the Compensation Committee generally considers the deductibility of compensation when making decisions, the Compensation Committee retains the right to pay nondeductible compensation to our named executive officers in order to maintain its flexibility in structuring appropriate compensation programs it feels to be appropriate.

Post Termination or Compensation and Benefits

We maintain a change of control severance plan (the “Severance Plan”), covering all employees, including the Named Executive Officers. The purpose of the severance plan is to promote stability and continuity of management and employees in the event a change of control transaction should occur (as defined below). Pursuant to the terms of our Severance Plan, our Named Executive Officers are entitled to receive certain post-termination compensation and benefits upon the occurrence of certain events. In order for the Named Executive Officers to receive payments under the Severance Plan, the Named Executive Officers would have to be terminated within two years of a change of control. See “Narrative Disclosure to Summary

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Compensation Table and Grants of Plan-Based Awards Table" and "Potential Payments upon Termination or Change of Control" below.

Consideration of Previous Shareholder Advisory Vote

In August 2013, our shareholders approved the compensation of our Named Executive Officers as described in our 2013 proxy statement, with approximately 92% of shareholder votes cast in favor of our 2013 "say-on-pay" resolution (excluding abstentions and broker non-votes). The Compensation Committee considered these results as evidence of broad-based support for our compensation program and decisions as described in our 2013 proxy statement, and as grounds for maintaining a similar approach for 2014.

Hedging Prohibitions

Our insider trading policy prohibits our Named Executive Officers from engaging in any speculative transactions involving our common shares including buying or selling puts or calls, short sales or purchases of securities on margin or otherwise hedging the risk of ownership of our stock. Any such activity would require the approval and authorization of either the CEO or the Chairman of the Audit Committee (in the case of a transaction involving our CEO).

Summary Compensation and Awards

The following table and discussion below sets forth information about the compensation awarded to, earned by or paid to our Named Executive Officers during the years ended December 31, 2013, 2012 and 2011:

Name and Principal Position	Year	Base Salary	Bonus	Restricted Stock and PBUs [1]	All Other Compensation[3]	Total
J. Russell Porter	2013	$500,000	$489,378	$1,158,393	$10,200	$2,157,971
President and Chief	2012	$500,000	$393,750	$750,000	$10,000	$1,653,750
Executive Officer	2011	$500,000	$162,731	$700,001	$9,800	$1,372,532
Michael A. Gerlich	2013	$300,000	$234,901	$656,111	$10,200	$1,201,212
Senior Vice President and	2012	$300,000	$189,000	$375,000	$10,000	$874,000
Chief Financial Officer	2011	$300,000	$65,093	$375,000	$9,800	$749,893
Michael McCown[2]	2013	$300,000	$221,851	$403,449	$10,033	$935,333
Senior Vice President and						
Chief Operating Officer						

(1) The dollar values of restricted stock and PBUs awards provided are equal to the aggregate grant date fair value of such grants awarded to Messrs. Porter and Gerlich during the years ended December 31, 2013, 2012 and 2011 and to Mr. McCown during the year ended December 31, 2013 calculated in accordance with Accounting Standards Codification Topic 718 ("ASC 718") prior to a deduction for estimated forfeitures related to service-based conditions. For a description of the assumptions used in calculating these amounts for 2013, see Note 9, "Equity Compensation Plans" to our consolidated financial statements filed with this Form 10-K.

(2) Mr. McCown was appointed as an executive officer on June 7, 2013.

(3) All other compensation includes the Company's contribution to the named executive officer's retirement plan.

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The following table shows certain information about the restricted common shares and PBUs granted to our Named Executive Officers during the year ended December 31, 2013.

		Estimated Future Payout Under Equity Incentive Plan Awards[(2)]					
Name	Date	Threshold	Target	Maximum	Grant Date Fair Value of PBUs[(1)]	All Other Equity Awards: Number of Shares of Stock	Grant Date Fair Value of Stock Awards[(1)]
J. Russell Porter	1/30/2013	—	—	—	—	484,914	$562,500
J. Russell Porter	1/30/2013	—	381,983	763,966	$595,893	—	$—
Michael A. Gerlich	1/30/2013	—	—	—	—	242,457	$281,250
Michael A. Gerlich	1/30/2013	—	240,302	480,604	$374,871	—	$—
Michael McCown	1/30/2013	—	—	—	—	168,103	$195,000
Michael McCown	1/30/2013	—	133,621	267,242	$208,449	—	$—

(1) The fair value of the respective restricted share and PBU grants as of the grant date is calculated in accordance with ASC 718. These shares and units are subject to a 3-year vesting schedule of 33.33% each year, beginning on the first anniversary date of the grant. Upon vesting, the PBUs can be settled at 0% to 200% depending upon our stock price performance.

(2) The estimated future payout for PBUs assumes a target payout of 100% of units granted and a maximum payout of 200% of units granted. For additional information, see "Compensation Discussion & Analysis."

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards

The following is a narrative of our various compensation plans and the general terms of each:

2006 Plan. At the annual meeting of shareholders held June 4, 2009, the shareholders approved amendments to our 2006 Long-Term Stock Incentive Plan that, effective as of April 1, 2009, merged our Stock Option Plan with and into the 2006 Long-Term Stock Incentive Plan so that all outstanding equity awards and all future equity awards to be made to employees, officers and directors would be under one plan–the "2006 Plan."

Our 2006 Plan, as amended, authorizes our 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 our directors, officers and employees and our subsidiaries covering a maximum of 11 million common shares. The contractual lives and vesting periods for grants are determined by the Board at the time a grant is awarded.

On March 8, 2012, our Board approved an amendment to the 2006 Plan, and such amendment was approved by the shareholders on June 7, 2012 at the annual meeting of shareholders. The Second Amendment to the Gastar Exploration Ltd. 2006 Long-Term Stock Incentive Plan (i) increased the maximum number of shares available for delivery pursuant to awards under the 2006 Plan by an additional 5,000,000 shares to 11,000,000 and (ii) increased the annual limit on the number of shares that may be subject to awards granted to any employee under the 2006 Plan in any calendar year from 200,000 shares to 1,000,000 shares.

As a result of the merger, the 2006 Plan maintained by Parent was assumed by Gastar Exploration Inc.and, effective as of the merger, was amended, restated and renamed the "Gastar Exploration Inc. Long-Term Incentive Plan" (the "LTIP"). The LTIP provides for substantially the same terms as the 2006 Plan, except the LTIP provides for awards with respect to Gastar Exploration Inc common stock rather than Parent common stock. All unexercised and unexpired options to purchase Parent common stock, restricted shares of Parent and other rights to acquire Parent common stock under the 2006 Plan (including performance-based units) became options to purchase, restricted stock or other rights to acquire the same number of shares of Gastar Exploration Inc pursuant to the LTIP, subject to the same terms and conditions, including the per share exercise price (but, in the case of performance awards, performance from and after the effective time of the merger will be determined with respect to the stock price of Gastar Exploration Inc rather than Parent).

Employee Severance Plan. For the Named Executive Officers, the Severance Plan provides that if a Named Executive Officer's employment is terminated within two years following a change of control for any reason other than (i) death, (ii) disability, (iii) by us for "cause" or (iv) by the Named Executive Officer for other than a "good reason," the Named Executive Officer will receive a lump-sum payment equal to a multiple that is equal to the applicable severance period, as set forth in the Severance Plan, times the sum of (1) his annual salary and (2) annual target bonus.

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A change of control is defined in the severance plan to mean (1) the consummation of a merger, consolidation, reorganization or other transaction whereby our shareholders retain less than 50% control, directly or indirectly, of us or the surviving company, (2) our incumbent directors cease to constitute a majority of the Board or (3) a sale or other disposition of all or substantially all of our assets. The Severance Plan does not change the specific, non-change of control severance payments in place under the existing employment agreements with our Named Executive Officers but does provide change of control severance benefits to the Named Executive Officers only if they are greater than the severance benefits provided under the employment agreement. The Severance Plan does not allow for any duplication of severance benefits.

The following summarizes the severance periods and target bonus percentages for the Named Executive Officers set forth in the Severance Plan, as amended:

	Severance Period In Years	Target Bonus Percentage	
Chief Executive Officer	3.00	75	%
Chief Financial Officer	2.50	60	%
Chief Operating Officer	2.50	60	%

Additionally, during the applicable severance period, Named Executive Officers would receive reimbursement for the cost of COBRA continuation health care coverage, less the amount charged at the time of termination to the employee for medical coverage.

If the Named Executive Officer receives a payment or benefit that is subject to the “golden parachute” excise tax, the Named Executive Officer will receive an additional payment under the severance plan to make him or her “whole” for that excise tax and any taxes on the additional parachute tax gross-up payment.

If the individual’s employment is terminated within six months prior to a change of control and it is reasonably shown to have been in connection with the change of control, then the change of control will be treated with respect to that employee as having occurred prior to his or her termination.

Employment Agreements. We entered into employment agreements with J. Russell Porter, our President and CEO, and Michael A. Gerlich, our CFO, effective February 24, 2005, and May 17, 2005, respectively, each amended July 25, 2008. Mr. Porter’s employment agreement was amended on February 3, 2011 to remove a provision that allowed him to trigger severance payments by providing the Company with six months’ notice. Mr. Gerlich's employment agreement was amended on April 10, 2012 (effective as of January 1, 2012) to reflect the change in his target bonus amount used for purposes of determining his severance entitlement under his employment agreement. The agreements with Messrs. Porter and Gerlich set forth, among other things, annual compensation, and adjustments thereto, minimum bonus payments, fringe benefits, termination and severance provisions. The agreements renew annually; however, they may be terminated at any time with or without cause.

Mr. Porter’s employment agreement provides that he is entitled to a minimum annual bonus in an amount that may take the form of cash compensation, the award of stock or stock options, royalty rights or otherwise and that he shall receive an annual cash bonus equal to at least 20% of his annual base salary. The employment agreement further provides that such bonuses shall reflect not only the results of our operations and business, but also his contribution as President and CEO.

Mr. Gerlich’s employment agreement provides that the Compensation Committee may on a yearly basis, or more frequently, award Mr. Gerlich a discretionary bonus or bonuses based not only on the positive results of our operations and business, but Mr. Gerlich’s contribution as CFO. Such bonuses may take the form of cash compensation, the award of common shares or stock options, royalty rights or otherwise.

Mr. McCown was not party to an employment agreement during 2013 and is not currently party to an employment agreement with the Company. However, consistent with its general policies regarding the compensation of named executive officers, the Company anticipates entering into an employment agreement with Mr. McCown on terms similar to those provided to the Company’s other named executive officers.

Salary and Cash Bonus in Proportion to Total Compensation

The following table sets forth the percentage of each Named Executive Officer’s total compensation that we paid in the form of base salary and cash bonus (excluding long-term incentive cash awards) for the year 2013.

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	Base Salary and Cash Bonuses as a Percentage of Total Compensation	
J. Russell Porter	50	%
Michael A. Gerlich	48	%
Michael McCown	59	%

Outstanding Equity Awards at Fiscal Year-End 2013

The following table sets forth information about outstanding equity awards held by our Named Executive Officers as of December 31, 2013:

		Option Awards				PBU Awards		Stock Awards	
Name	Grant Date	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Option Exercise Price	Option Expiration Date	Number of PBUs That Have Not Vested(1)	Market Value of PBUs That Have Not Vested(1)	Number of Shares of Restricted Stock That Have Not Vested	Market Value of Shares of Restricted Stock That Have Note Vested (2)
J. Russell Porter (2)	4/5/2006	30,000	—	$ 20.51	4/5/2016	—	—	—	—
	7/14/2006	200,000	—	$ 11.60	7/14/2016	—	—	—	—
	3/19/2009	30,000	—	$ 2.60	3/19/2019	—	—	—	—
	1/30/2013	—	—	—	—	381,983	$5,317,203	—	—
	3/26/2010	—	—	—	—	—	—	31,250	$216,250
	3/15/2011	—	—	—	—	—	—	83,933	$580,816
	1/30/2012	—	—	—	—	—	—	168,919	$1,168,919
	1/30/2013	—	—	—	—	—	—	484,914	$3,355,605
Michael A. Gerlich (3)	1/16/2006	50,000	—	$ 21.60	1/16/2016	—	—	—	—
	4/5/2006	20,000	—	$ 20.51	4/5/2016	—	—	—	—
	7/14/2006	60,000	—	$ 11.60	7/14/2016	—	—	—	—
	3/19/2009	20,000	—	$ 2.60	3/19/2019	—	—	—	—
	1/30/2013	—	—	—	—	240,302	$3,345,004	—	—
	3/26/2010	—	—	—	—	—	—	21,875	$151,375
	3/15/2011	—	—	—	—	—	—	44,964	$311,151
	1/30/2012	—	—	—	—	—	—	84,659	$585,840
	1/30/2013	—	—	—	—	—	—	242,457	$1,677,802
Michael McCown (4)	1/30/2013	—	—	—	—	133,621	$1,860,004	—	—
	8/5/2010	—	—	—	—	—	—	5,000	$34,600
	3/15/2011	—	—	—	—	—	—	24,461	$169,270
	1/30/2012	—	—	—	—	—	—	58,559	$405,228
	1/30/2013	—	—	—	—	—	—	168,103	$1,163,273

(1) For purposes of this table, we assumed that the unvested PBUs will vest at the target of 100% with a fair value of $13.92 per unit on December 31, 2013.

(2) The closing price of our common shares on December 31, 2013 was $6.92.

(3) The 31,250 unvested restricted common shares granted to Mr. Porter on March 26, 2010 vest 100% on March 26, 2014. The 83,933 unvested restricted common shares granted to Mr. Porter on March 15, 2011 vest 50% on March 15, 2014 and 2015, respectively. The 168,919 unvested restricted shares granted to Mr. Porter on January 30, 2012 vest

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50% on January 30, 2014 and 2015, respectively. The 484,914 unvested restricted shares granted to Mr. Porter on January 30, 2013 vest 33.3% on January 30, 2014. 2015 and 2016, respectively.

(4) The 21,875 unvested restricted common shares granted to Mr. Gerlich on March 26, 2010 vest 100% on March 26, 2014. The 44,964 unvested restricted common shares granted to Mr. Gerlich on March 15, 2011 vest 50% on March 15, 2014 and 2015, respectively. The 84,659 unvested restricted shares granted to Mr. Gerlich on January 30, 2012 vest 50% on January 30, 2014 and 2015, respectively. The 242,457 unvested restricted common shares granted to Mr. Gerlich on January 30, 2013 vest 33.3% on January 30, 2014, 2015 and 2016, respectively.

(5) The 5,000 unvested restricted common shares granted to Mr. McCown on August 5, 2010 vest 100% on August 5, 2014. The 24,461 unvested restricted common shares granted to Mr. McCown on March 15, 2011 vest 50% on March 15, 2014 and 2015, respectively. The 58,559 unvested restricted common shares granted to Mr. McCown on January 30, 2012 vest 50% on January 30, 2014 and 2015, respectively. The 168,103 unvested restricted common shares granted to Mr. McCown on January 30, 2013 vest 33.3% on January 30, 2014, 2015 and 2016, respectively.

Option Exercises and Stock Vested for 2013

During the year ended December 31, 2013, our Named Executive Officers exercised no stock options. The following restricted common shares vested to the benefit of our Named Executive Officers during 2013:

	Stock Awards			
Name	Grant Date	Vesting Date	Number of Shares Acquired on Vesting	Value Realized on Vesting (1)
J. Russell Porter	3/19/2009	3/19/2013	3,750	$5,100
	9/4/2009	9/4/2013	41,250	$134,063
	3/26/2010	3/26/2013	31,250	$54,688
	3/15/2011	3/15/2013	41,966	$55,395
	1/30/2012	1/30/2013	84,459	$97,973
Michael A. Gerlich	3/19/2009	3/19/2013	2,500	$3,400
	9/4/2009	9/4/2013	25,000	$81,250
	3/26/2010	3/26/2013	21,875	$38,281
	3/15/2011	3/15/2013	22,482	$29,676
	1/30/2012	1/30/2013	42,230	$48,986
Michael McCown	8/5/2010	8/5/2013	5,000	$16,850
	3/15/2011	3/15/2013	12,231	$16,145
	1/30/2012	1/30/2013	29,279	$33,964

(1) Equals the closing stock price of our common shares on the day prior to the applicable vesting date multiplied by the number of restricted shares vesting on such date.

Potential Payments Upon Termination or Change of Control

The table below discloses the amount of compensation and/or other benefits due to the Named Executive Officers in the event of their termination of employment, including, but not limited to, in connection with a change in control. The amounts shown for Messrs. Porter, Gerlich and McCown below assume that such termination was effective as of December 31, 2013, and thus include amounts earned through such date and are estimates of the amounts that would be paid to the Named Executive Officers upon their respective termination. The actual amounts to be paid can only be determined at the time the Named Executive Officer is terminated.

As described above, Mr. McCown was not party to an employment agreement during 2013 and is not currently party to an employment agreement with the Company. However, consistent with its general policies regarding the compensation of named executive officers, the Company anticipates entering into an employment agreement with Mr. McCown on terms similar to those provided to the Company’s other named executive officers.

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Named Executive Officer and Post Termination Benefits	Termination for other than Reasonable Cause (1)	Constructive Termination and Termination in Connection with Change of Control (2)	Termination for Reasonable Cause (3)	Death (1)(4)	Disability (1)(4)
J. Russell Porter:					
Salary	$2,250,000	$2,625,000	$—	$2,250,000	$2,250,000
Accrued Vacation	21,634	21,634	21,634	21,634	21,634
Paid health and medical	30,042	30,042	—	30,042	30,042
Parachute tax gross-up payment (5)	—	4,420,603	—	—	—
Equity compensation (6)	—	7,964,913	—	—	—
Total	$2,301,676	$15,062,192	$21,634	$2,301,676	$2,301,676
Michael A. Gerlich:					
Salary	$1,200,000	$1,200,000	$—	$1,200,000	$1,200,000
Accrued Vacation	17,885	17,885	17,885	17,885	17,552
Paid health and medical	30,042	30,042	—	30,042	30,042
Parachute tax gross-up payment (5)	—	2,337,740	—	—	—
Equity compensation (6)	—	4,387,674	—	—	—
Total	$1,247,927	$7,973,341	$17,885	$1,247,927	$1,247,594
Michael McCown:					
Salary	$—	$1,200,000	$—	$—	$—
Accrued Vacation	—	14,423	14,423	—	—
Paid health and medical	—	30,042	—	—	—
Parachute tax gross-up payment (5)	—	—	—	—	—
Equity compensation (6)	—	2,697,022	—	—	—
Total	$—	$3,941,487	$14,423	$—	$—

(1) Per Mr. Porter's employment agreement, if he is involuntarily terminated for any reason other than for Reasonable Cause (as defined below) and if proper notice is received, Mr. Porter will be entitled to a lump sum severance payment equal to the product of 4.5 multiplied by the highest annual base salary in effect at any time during the one year period preceding his termination. At December 31, 2013, Mr. Porter's severance was calculated by multiplying $500,000 by 4.5. If Mr. Porter is considered a "specified employee" under Section 409A of the Code at the time of his termination, this payment will be delayed for a period of six months if necessary to avoid the additional excise tax under Section 409A of the Code. If Mr. Porter timely elects COBRA continuation coverage, he and his family will be entitled to continuation of health insurance at our expense, subject to the limitations imposed by law and our insurance plan, which is currently 18 months (the "COBRA Continuation Period"). As of December 31, 2013, the cost for health and medical coverage for Mr. Porter as an employee was $1,669 per month. Mr. Porter currently is entitled to 20 working days of vacation per year. He would receive a lump-sum cash payment of his unused vacation time of up to 10 days that are not used during each year employed. As of December 31, 2013, Mr. Porter had available 17.11 days of accrued but unused vacation pay. In addition, effective on Mr. Porter's termination for any reason other than Mr. Porter elects to terminate his own employment, the unvested portion of all stock options held by Mr. Porter will immediately vest and be exercisable for a period of 90 days. All other terms and conditions of his stock options will remain unchanged, including provision that all stock options will terminate 90 days after Mr. Porter's termination. As of December 31, 2013, Mr. Porter had no unvested stock options to acquire common shares and he had 30,000 vested stock options that were "in-the-money" that would be exercised upon his termination of employment. On December 31, 2013, he had 769,016 unvested restricted common shares, which would be canceled upon his termination. On December 31, 2013, Mr. Porter had 116,717

unvested PBUs that would vest upon termination and 265,266 unvested PBUs, which would be canceled upon his termination.

Per Mr. Gerlich's employment agreement, if he is involuntarily terminated for any reason other than for Reasonable Cause (as defined below), he will be entitled to a lump sum severance payment equal to the product of 2.5 and the sum

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of (1) his highest annual base salary in effect at any time during the one year period preceding his termination (at December 31, 2013, this amount was $300,000) and (2) his target bonus amount of 60% of his base salary ($180,000). If Mr. Gerlich is considered a "specified employee" under Section 409A of the Code at the time of his termination, this payment will be delayed for a period of six months if necessary to avoid the additional excise tax under Section 409A of the Code. If Mr. Gerlich timely elects COBRA continuation coverage, he and his family will be entitled to continuation of health insurance at our expense, during the COBRA Continuation Period. If Mr. Gerlich dies during the COBRA Continuation Period, his family will be entitled to continuation of health insurance at our expense, subject to the limitations imposed by law and our insurance plan. At December 31, 2013 the maximum cost over the 18-month period was $1,669 per month. In addition, Mr. Gerlich will receive a lump-sum cash payment of his unused vacation time of up to 10 days per each year employed, up to a maximum of 15 days. As of December 31, 2013, Mr. Gerlich had 13.78 days of available accrued but unused vacation pay. Per Mr. Gerlich's stock option agreements, he will have 90 days after termination to exercise all vested options. As of December 31, 2013, Mr. Gerlich did not have any unvested options and had 20,000 vested options that were "in-the-money" that would be exercised upon his termination of employment. Additionally, on December 31, 2013, he had 393,755 unvested restricted common shares, which would be canceled upon his termination. On December 31, 2013, Mr. Gerlich had 73,426 unvested PBUs that would vest upon termination and 166,876 unvested PBUs, which would be canceled upon his termination.

On December 31, 2013, Mr. McCown had 256,122 unvested restricted common shares, which would be canceled upon his termination. On December 31, 2013, Mr. McCown had 40,829 unvested PBUs that would vest upon termination and 92,792 unvested PBUs, which would be canceled upon his termination.

(2) The Severance Plan provides that if an employee incurs an involuntary termination within a two-year period following a change of control, covered employees, including Named Executive Officers, will receive a lump-sum cash payment equal to the applicable severance period times the sum of the covered employee's annual pay and target bonus, contingent on the employee executing a full release and settlement agreement. Mr. Porter's severance period is 3 years, and his annual salary and 75% target bonus at December 31, 2013 were $500,000 and $375,000, respectively. Mr. Gerlich's severance period is 2.5 years, and his annual salary and 60% target bonus at December 31, 2013 were $300,000 and $180,000, respectively. Mr. McCown's severance period is 2.5 years, and his annual salary and 60% target bonus at December 31, 2013 were $300,000 and $180,000, respectively. The Employee Severance Plan provides that if there is a change of control, covered employees, including Named Executive Officers, will be eligible to receive reimbursement of COBRA costs. Other termination or severance compensation is determined by the individual Named Executive Officer's employment agreement. The employment agreements we have with both Messrs. Porter and Gerlich provide that the amounts received as severance under their employment agreements will offset any benefits provided by the Severance Plan; because each of the executives would receive the same amount of severance under their employment agreements as under the Severance Plan as of December 31, 2013 the only additional cash benefit provided under the Severance Plan is the gross-up payment for taxes. Additionally, the award agreements for the Named Executive Officers restricted stock, PBUs and stock option agreements provide for the acceleration of vesting upon a change of control, thus the amounts in the table above reflect the acceleration of the outstanding restricted stock and PBUs awards each Named Executive Officer held as of December 31, 2013. As of December 31, 2013, no stock option awards were unvested so no value has been included in the table above with respect to the accelerated vesting of stock options.

(3) Per their respective employment agreements, we are not obligated to pay any amounts to Messrs. Mr. Porter or Gerlich other than accrued and unused vacation days and their pro-rata base salary through the date of his termination of employment, as a result of a termination for Reasonable Cause (as defined below). Only the stock options held by each executive that were already vested as of December 31, 20132, would remain eligible for exercise following his termination of employment.

(4) Per their respective employment agreements, if Messrs. Porter's or Gerlich's employment terminates due to death, his eligible beneficiary will be entitled to receive his severance payment as described in Footnote 1 above. If Messrs. Porter's or Gerlich's employment terminates due to Disability (as defined below), he shall be entitled to receive a severance payment in the form and amount as determined in Footnote 1 above.

(5) Our Severance Plan provides that if the Named Executive Officer receives a payment or benefit that is subject to the “golden parachute” excise tax, the Named Executive Officers will receive an additional payment under the severance plan to make him or her “whole” for that excise tax and any taxes on the additional parachute tax gross-up payment (the “gross-up payment”). If the total payments provided to an individual that were contingent on a change in control exceed three times an individual’s “base amount,” that individual is considered to be receiving a “parachute payment.” If the individual is considered to have received a “parachute payment,” then a tax will be imposed on any “excess parachute payment” amount, which is the amount in excess of one times the individual’s “base amount.” To determine Messrs. Porter’s and Gerlich’s amount of the gross-up payment, Messrs. Porter’s and Gerlich’s “base amount” was calculated using the five-year average of his compensation for the years 2008-2012. In making the calculation, the following assumptions were used: (a) the change of control occurred on December 31, 2013, (b) the closing price of

our stock was \$6.92 on such date, (c) the excise tax rate under Section 4999 of the Code is 20%, the federal income tax rate is 35%, the Medicare rate is 1.45%, the adjustment to reflect the phase-out of itemized deductions is 1.05%, and there is no state or local income taxes, (d) no amounts will be discounted as attributable to reasonable compensation, (e) all cash severance payments are contingent upon a change of control, (f) the presumption required under applicable regulations that the equity awards granted were contingent upon a change of control could be rebutted. To determine Mr. McCown's amount of the gross-up payment, which calculated to \$0, Mr. McCown's "base amount" was calculated using 2013 compensation. In making the calculation, the following assumptions were used: (a) the change of control occurred on December 31, 2013, (b) the closing price of our stock was \$6.92 on such date, (c) the excise tax rate under Section 4999 of the Code is 20%, the federal income tax rate is 35%, the Medicare rate is 1.45%, the adjustment to reflect the phase-out of itemized deductions is 1.05%, and 6% state or local income taxes, (d) no amounts will be discounted as attributable to reasonable compensation, (e) all cash severance payments are contingent upon a change of control, (f) the presumption required under applicable regulations that the equity awards granted were contingent upon a change of control could be rebutted.

(6) The award agreements for the Named Executive Officers restricted stock, PBUs and stock options agreements provide for the acceleration of vesting upon a change of control, thus the amounts in the table above reflect the acceleration of the outstanding PBUs and restricted stock awards each Named Executive Officer held as of December 31, 2013. As of December 31, 2013, no stock option awards were unvested so no value has been included in the table above with respect to the accelerated vesting of stock options. The amount shown is the product of the number of restricted shares and PBUs held by the Named Executive Officer times the closing price of our common shares on December 31, 2013 or \$6.92 per common share.

The employment agreements of Messrs. Porter and Gerlich generally use the following terms:

"Reasonable Cause" means any of the following (a) an act or omission that amounts to dishonesty, disloyalty, fraud, deceit, gross negligence, willful misconduct or recklessness, including the willful violation of any of our policies or procedures; (b) a felony conviction; (c) a breach of any material term of the employment agreement; (d) the refusal to perform any services that the Named Executive Officer is required to perform under the employment agreement; or (e) with respect to Mr. Porter's agreement only, an act that is determined by the vote of two-thirds of the shareholders to constitute "Reasonable Cause" or to be detrimental to our best interests.

"Disability" means the inability to perform the functions essential to the Named Executive Officer's position with or without accommodation during a continuous 12 month period, due to physical or mental illness of the Named Executive Officer. The date of disability is the last day of the 12-month period. Successive periods of illness or injury that are due to the same or related causes are considered one period of disability unless the Named Executive Officer returns to work full-time for three successive months.

Under Mr. Gerlich's employment agreement, a "change of control" occurs as a result of a sale of all or substantially all of our assets, purchase of over 50% of our stock, or through merger, consolidation, corporate restructuring or otherwise.

The Severance Plan generally uses the following terms:

"Change of Control" means (1) the consummation of a merger, consolidation, reorganization or other transaction whereby our shareholders retain less than 50% control, directly or indirectly, of us or the surviving company, (2) our incumbent directors cease to constitute a majority of the Board or (3) a sale or other disposition of all or substantially all of our assets, or (4) the Board's adoption of a plan of dissolution or liquidation for us.

"Involuntary Termination" means any termination of employment that occurs within two years following a Change of Control and which (1) is by us other than for cause (but excluding a termination due to the employee's failure to accept comparable employment), or (2) is by the employee for Good Reason. An "Involuntary Termination" does not include: (a) a termination of the employee by us for cause, (b) a termination of the employee due to his death or disability, (c) a voluntary resignation by the employee other than for Good Reason, or (d) any termination of the employee by the employer as a result of the employee declining to accept an offer of comparable employment with a successor employer.

"Good Reason" means the occurrence of any of the following events after a Change of Control: (1) relocating the covered employee's place of employment without his consent to a place that would constitute a material change in his place of employment 2) reducing the covered employee's annual base salary or (3) a substantial reduction in the covered employee's position or responsibilities. In certain circumstances, the occurrence of one of these events within six months prior to the Change of Control may be Good Reason.

The Severance Plan provides that if any payment made, or benefit provided, to or on behalf of a covered employee pursuant to the plan or otherwise ("Payments") results in a covered employee being subject to the excise tax imposed by Section 4999 of the Code (or any successor or similar provision) ("Excise Tax"), we shall, as soon as administratively practicable, pay such covered employee an additional amount in cash (the "Additional Payment") such that after payment by

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the covered employee of all taxes, including, without limitation, any taxes imposed on the Additional Payment, such Covered Employee retains an amount of the Additional Payment equal to the Excise Tax imposed on the Payments. Such determinations shall be made by our independent certified public accounting firm.

Mr. Porter's employment agreement contains a confidentiality provision applicable both during the term of his employment and following his termination of employment. Pursuant to the confidentiality provision, Mr. Porter agrees to hold in confidence and not disclose any confidential information about our business, except as required in the ordinary course of performing his employment duties with us. A breach of this confidentiality provision could result in a Reasonable Cause termination. Mr. Porter's employment agreement further provides that, for a period of two years after his termination of employment with us for a reason other than Reasonable Cause (six months if terminated for Reasonable Cause). Mr. Porter shall not compete with us directly or indirectly.

Mr. Gerlich's employment agreement provides that, unless specifically pre-approved by the CEO in writing, which approval may not be unreasonably withheld, Mr. Gerlich will not directly compete (as defined in the employment agreement) with us for a period of two years following his termination of employment.

Risk Assessment

The Compensation Committee uses the structural elements set forth in this Part III on Form 10-K to establish compensation that will provide sufficient incentives for Named Executive Officers to drive results while avoiding unnecessary or excessive risk taking that could harm the long-term value of the Company. During 2013, the Compensation Committee reviewed the Company's assessment of risk created by the Company's compensation policies and practices, which was conducted with guidance from the independent compensation consultant. The Compensation Committee concluded that our compensation policies and practices do not create risks that are reasonably likely to have a material adverse effect on the Company.

Director Compensation

For the year ended December 31, 2013, non-employee directors received the following fees:

- $2,917 per month, paid semi-annually;
- An aggregate of $15,000 per year for the Chairman of the Board;
- An aggregate of $10,000 for the Chairman of the Audit Committee;
- An aggregate of $7,500 per year or both the Chairman of the Compensation Committee and the Chairman of the Nominating and Corporate Governance Committee; and
- $1,000 for each meeting of the Board attended in person and $500 for each meeting attended telephonically. No additional fees are paid for attendance at committee meetings.

We also grant to our non-employee directors restricted common shares under our stock-based compensation plan in addition to their specified cash compensation to be paid as directors. These grants are, in part, to compensate our directors for the strict regulatory role in which they have to operate and to provide them with incentives to remain as a director by offering them a long-term stake in our potential future value.

The following table shows certain information about non-employee director compensation for the year ended December 31, 2013:

Director Compensation Table

Director	Fees Earned or Paid in Cash (1)	Common Shares (2)	Total
John H. Cassels	$62,000	$132,590	$194,590
Randolph C. Coley	$62,000	$132,590	$194,590
Robert D. Penner	$64,500	$132,590	$197,090
John M. Selser	$89,500	$190,180	$279,680

(1) Includes a special payment for additional responsibilities and duties during 2013.

(2) Amounts reflect the grant date fair value of restricted common stock grants awarded to each of our outside directors during the year ended December 31, 2013, calculated in accordance with ASC 718 prior to a deduction for estimated forfeitures related to service-based vesting conditions.

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The following table sets forth information about outstanding equity awards held by our Directors as of December 31, 2013:

		Option Awards				Stock Awards	
Name	Grant Date	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Option Exercise Price	Option Expiration Date	Number of Shares of Restricted Stock That Have Not Vested	Market Value of Shares of Restricted Stock That Have Not Vested [1]
John H. Cassels [2]	3/15/2011	—	—	—	—	8,992	$62,225
	1/30/2012	—	—	—	—	16,892	$116,893
	1/30/2013	—	—	—	—	64,655	$447,413
	11/11/2013	—	—	—	—	13,000	$89,960
Randolph C. Coley [3]	1/14/2010	30,000	—	$4.27	1/14/2020	—	—
	3/26/2010	—	—	—	—	3,750	$25,950
	3/15/2011	—	—	—	—	8,992	$62,225
	1/30/2012	—	—	—	—	16,892	$116,893
	1/30/2013	—	—	—	—	64,655	$447,413
	11/11/2013	—	—	—	—	13,000	$89,960
Robert D. Penner [4]	7/9/2007	40,000	—	$10.95	7/9/2017	—	—
	3/19/2009	15,000	—	$2.60	3/19/2019	—	—
	3/26/2010	—	—	—	—	3,750	$25,950
	3/15/2011	—	—	—	—	8,992	$62,225
	1/30/2012	—	—	—	—	16,892	$116,893
	1/30/2013	—	—	—	—	64,655	$447,413
	11/11/2013	—	—	—	—	13,000	$89,960
John M. Selser Sr. [5]	3/30/2007	40,000	—	$10.85	3/30/2017	—	—
	7/3/2007	20,000	—	$11.00	7/3/2017	—	—
	3/19/2009	15,000	—	$2.60	3/19/2019	—	—
	3/26/2010	—	—	—	—	3,750	$25,950
	3/15/2011	—	—	—	—	8,992	$62,225
	1/30/2012	—	—	—	—	16,892	$116,893
	1/30/2013	—	—	—	—	64,655	$447,413
	11/11/2013	—	—	—	—	26,000	$179,920

(1) The closing price of our common shares on December 31, 2013 was $6.92.

(2) The 8,992 unvested restricted common shares granted to Mr. Cassels on March 15, 2011 vest 50.0% on March 15, 2014 and 2015, respectively. The 16,892 unvested restricted shares granted to Mr. Cassels on January 30, 2012 vest 50.0% on January 30, 2014 and 2015, respectively. The 64,655 unvested restricted common shares granted to Mr. Cassels on January 30, 2013 vest 33.3% on January 30, 2014, 2015 and 2016, respectively. The 13,000 unvested restricted common shares granted to Mr. Cassels on November 11, 2013 vest 33.3% on November 11, 2014, 2015 and 2016, respectively.

(3) The 10,000 unvested stock options granted to Mr. Coley on January 14, 2010 vest 100.0% on January 14, 2014. The 3,750 unvested restricted common shares granted to Mr. Coley on March 26, 2010 vest 100.0% on March 26, 2014. The 8,992 unvested restricted common shares granted to Mr. Coley on March 15, 2011 vest 50.0% on March 15, 2014 and 2015, respectively. The 16,892 unvested restricted common shares granted to Mr. Coley on January 30, 2012 vest 50.0% on January 30, 2014 and 2015, respectively. The 64,655 unvested restricted common shares granted to Mr. Coley on January 30, 2013 vest 33.3% on January 30, 2014, 2015 and 2016, respectively. The

13,000 unvested restricted common shares granted to Mr. Coley on November 11, 2013 vest 33.3% on November 11, 2014, 2015 and 2016, respectively.

(4) The 3,750 unvested restricted common shares granted to Mr. Penner on March 26, 2010 vest 100.0% on March 26, 2014. The 8,992 unvested restricted common shares granted to Mr. Penner on March 15, 2011 vest 50.0% on March

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15, 2014 and 2015, respectively. The 16,892 unvested restricted common shares granted to Mr. Penner on January 30, 2012 vest 50.0% on January 30, 2014 and 2015, respectively. The 64,655 unvested restricted common shares granted to Mr. Penner on January 30, 2013 vest 33.3% on January 30, 2014, 2015 and 2016, respectively. The 13,000 unvested restricted common shares granted to Mr. Penner on November 11, 2013 vest 33.3% on November 11, 2014, 2015 and 2016, respectively.

(5) The 3,750 unvested restricted common shares granted to Mr. Selser on March 26, 2010 vest 100.0% on March 26, 2014. The 8,992 unvested restricted common shares granted to Mr. Selser on March 15, 2011 vest 50.0% on March 15, 2014 and 2015, respectively. The 16,892 unvested restricted common shares granted to Mr. Selser on January 30, 2012 vest 50.0% on January 30, 2014 and 2015, respectively. The 64,655 unvested restricted common shares granted to Mr. Selser on January 30, 2013 vest 33.3% on January 30, 2014, 2015 and 2016, respectively. The 26,000 unvested restricted common shares granted to Mr. Selser on November 11, 2013 vest 33.3% on November 11, 2014, 2015 and 2016, respectively.

For the year ending December 31, 2014, non-employee directors are expected to receive the fees listed below. The annual retainer fees are to be paid semi-annually in arrears including meeting fees for the prior quarters.

Annual director retainer	$45,000
Chairman of Board annual retainer	$25,000
Chairman of Audit Committee annual retainer	$15,000
Chairman of Compensation Committee annual retainer	$9,000
Chairman of Nominating and Corporate Governance Committee annual retainer	$7,500
In-person meeting attendance fees	$1,550
Fees for in-person committee meetings	$1,000

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2013, Messrs. Cassels, Coley and Selser each served as members of the Compensation Committee during all of the year. None of these directors is or has ever served as one of our officers or employees. None of our executive officers serves or has served as a director or member of a board of directors or compensation committee (or committee performing similar functions) of any other entity, one or more of whose executive officers serve on the Board or Compensation Committee.

Compensation Committee Report

Board of Directors of Gastar Exploration Inc.

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management and based on the review and discussions referred to above, the Compensation Committee recommends to the Board that the Compensation Discussion and Analysis be included in this Form 10-K.

Gastar Exploration Inc.
Compensation Committee
/s/ John H. Cassels, Chairman
/s/ Randolph C. Coley
/s/ John M. Selser Sr.

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

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information about the beneficial ownership of common stock and preferred stock by:

- Each of our directors;
- Each of our executive officers, as listed in the Summary Compensation Table, set forth under “Executive Compensation;”;
- All of our executive officers and directors as a group; and
- Each person known to us to be the beneficial owner of more than 5% of our outstanding common shares.

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The table below is based upon information supplied by executive officers, directors, principal shareholders and from documents filed with the SEC. Applicable percentages are based on 61,889,655 shares of common stock, 3,984,363 shares of Series A Preferred Stock and 2,140,000 shares of Series B Preferred Stock outstanding on March 11, 2014. To the knowledge of our directors and executive officers, as of March 11, 2014, no person, firm or corporation owns, directly or indirectly, or exercise control or direction over voting securities carrying more than 5% of the voting rights attached to any class of our voting securities, except as indicated below. Unless otherwise stated and subject to community property laws where applicable, management believes that all persons named in the following table have sole voting and investment power over all shares of common and preferred stock reported as beneficially owned by them.

Name and Address of Beneficial Owner	Common Stock Amount and Nature of Beneficial Ownership	Percent of Shares Outstanding	Series A Preferred Stock Amount and Nature of Beneficial Ownership	Percent of Shares Outstanding	Series B Preferred Stock Amount and Nature of Beneficial Ownership	Percent of Shares Outstanding
Our greater than 5% shareholders:						
Global Undervalued Securities Master Fund, L.P.[1]	4,190,000	6.8%				
301 Commerce Street, Suite 1900						
Fort Worth, Texas 76109						
Our non-employee directors [2]:						
John H. Cassels [3]	128,524	*	—	—%	—	—%
Randolph C. Coley [4]	178,546	*	—	—%	—	—%
Robert D. Penner [5]	231,773	*	—	—%	—	—%
John M. Selser Sr. [6]	275,950	*	16,032	*	4,500	*
Our executive officers [2]:						
J. Russell Porter, President and Chief Executive Officer [7]	2,357,703	3.8%	20,152	*	2,000	*
Michael A. Gerlich, Senior Vice President and Chief Financial Officer [8]	1,157,788	1.9%	1,725	*	—	—%
Michael McCown, Senior Vice President and Chief Operating Officer [9]	517,073	*	11,655	*	—	—%
Our directors and executive officers, as a group (6 persons)	4,847,357	7.8%	49,564	1.2%	6,500	*

* Less than 1%.

(1) Based upon a Schedule 13D filed in respect of Gastar Exploration, Inc. on December 23, 2013, as amended. Voting and dispositive power is shared with Kleinheinz Capital Partners, Inc., John B. Kleinheinz and Fred N. Reynolds.

(2) The contact address for our directors and executive officers is 1331 Lamar Street, Suite 650, Houston, Texas 77010. Individuals holding unvested restricted common shares have the right to vote those common shares.

(3) As of March 11, 2014, Mr. Cassels owned 37,741 common shares directly and beneficially held 90,783 unvested restricted common shares. Individuals holding unvested restricted common shares have the right to vote those common shares.

(4) As of March 11, 2014, Mr. Coley owned 44,013 common shares directly, beneficially held 94,533 unvested restricted common shares, and held stock options to purchase 40,000 common shares, all of which currently are vested and exercisable as of March 11, 2014 regardless of trading price. Individuals holding unvested restricted common shares have the right to vote those common shares.

(5) As of March 11, 2014, Mr. Penner owned 82,241 common shares directly, beneficially held 94,532 unvested restricted common shares, and held stock options to purchase 55,000 common shares, all of which currently are vested and exercisable as of March 11, 2014 regardless of trading price. Individuals holding unvested restricted common shares have the right to vote those common share.

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(6) As of March 11, 2014, Mr. Selser owned 93,418 common shares directly, beneficially held 107,532 unvested restricted common shares, and held stock options to purchase 75,000 common shares, all of which currently are vested and exercisable as of March 11, 2014 regardless of trading price. Individuals holding unvested restricted common shares have the right to vote those common share. Additionally, as of March 11, 2014, Mr. Selser directly owned 16,032 shares of Gastar USA 8.625% Series A Cumulative Preferred Stock and 4,500 shares of Gastar USA 10.75% Series B Cumulative Preferred Stock.

(7) As of March 11, 2014, Mr. Porter owned 1,087,371 common shares directly, beneficially held 639,298 unvested restricted common shares, held stock options to purchase 260,000 common shares, all of which currently are vested and exercisable as of March 11, 2014 regardless of trading price and held 371,034 unvested PBUs. Individuals holding unvested restricted common shares have the right to vote those common share. Additionally, as of March 11, 2014, Mr. Porter directly owned 20,152 shares of Gastar USA 8.625% Series A Cumulative Preferred Stock and 2,000 shares of Gastar USA 10.75% Series B Cumulative Preferred Stock.

(8) As of March 11, 2014, Mr. Gerlich owned 471,708 common shares directly, beneficially held 323,293 unvested restricted common shares, held stock options to purchase 150,000 common shares, all of which currently are vested and exercisable as of March 11, 2014 regardless of trading price and held 212,787 unvested PBUs. Individuals holding unvested restricted common shares have the right to vote those common share. Additionally, as of March 11, 2014, Mr. Gerlich directly owned 1,725 shares of Gastar USA 8.625% Series A Cumulative Preferred Stock.

(9) As of March 11, 2014, Mr. McCown owned 170,977 common shares directly, beneficially held 213,913 unvested restricted common shares and held 132,183 unvested PBUs. Individuals holding unvested restricted common shares have the right to vote those common share. Additionally, as of March 11, 2014, Mr. McCown directly owned 11,655 shares of Gastar USA 8.625% Series A Cumulative Preferred Stock.

Equity Compensation Plan Information

The following table provides information regarding securities authorized for issuance under our equity compensation plan as of December 31, 2013:

Plan Category	Number of Securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	874,100	$ 11.68	2,610,572
Equity compensation plans approved by security holders	1,065,734	n/a	1,544,838
Equity compensation plans not approved by security holders	—	—	—
Total	1,939,834	5.26	1,544,838

Item 13. Certain Relationships and Related Transactions and Director Independence

Certain Relationships and Related Transactions

Effective April 11, 2011, our Board adopted a formal written related party policy. These written policies and procedures for review, approval or ratification of related party transactions fall within the responsibilities of the Audit Committee. The Audit Committee reviews and approves all related party transactions. In the course of its review, the Audit Committee considers the nature of the transactions and the costs to be incurred by us or payments to us; an analysis of the costs and benefits associated with the transaction and a comparison of comparable or alternative goods or services that are available to us from unrelated parties; the business advantage we would gain by engaging in the transaction; and an analysis of the significance of the transaction to us and to the related party. As a matter of course, any Audit Committee member that cannot be viewed as independent with respect to the transaction at issue will withhold his vote and declare his interest in the transaction. A vote of a majority of the remaining members is required to approve a related party transaction.

Director Independence

The Board has determined that each member of the Board, with the exception of Mr. Porter, has no material relationship with us (either directly or as partners, shareholders or officers of an organization that has a relationship with us) and is independent within the meaning of the NYSE MKT LLC listing requirements and the rules and regulations of NI 58-101

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director independence standards. Mr. Porter, as our President and Chief Executive Officer, is not considered to be independent. Further, the Board has determined that each of the members of the Audit Committee, the Compensation Committee, the Nominating and Corporate Governance Committee and the Reserves Review Committee has no material relationship with us (either directly or as a partner, shareholder or officer of an organization that has a relationship with us) and is independent within the meaning of the NYSE MKT LLC listing requirements and the rules and regulations of NI 58-101 director independence standards.

Item 14. Principal Accountant Fees and Services

Audit Fees

Aggregate fees billed for professional services rendered to us by BDO USA, LLP, our principal independent registered public accounting firm, for the years ended December 31, 2013 and 2012 were:

	For the Years Ended December 31,	
	2013	2012
	(in thousands)	
Audit fees	$609	$334
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$609	$334

The audit fees for the years ended December 31, 2013 and 2012 were primarily for professional services rendered in connection with the audit of our consolidated financial statements; fees related to our compliance with the Sarbanes-Oxley Act of 2002; and services rendered in connection with quarterly reviews of financial statements and various documents filed with various governmental agencies. Audit fees for 2013 includes approximately $273,000 of audit services related to financing and acquisition activities.

Audit Committee Pre-Approval Policies and Procedures

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

PART IV

Item 15. Exhibits, Financial Statements and Schedules

(a) Financial Statements and Schedules:

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

(b) Exhibits:

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

EXHIBIT INDEX

Exhibit Number	Description
2.1**	Purchase and Sale Agreement, dated March 28, 2013, by and among Chesapeake Exploration, L.L.C., Arcadia Resources, L.P., Jamestown Resources, L.L.C., Larchmont Resources, L.L.C. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Quarterly Report on Form 10-Q filed with the SEC on May 2, 2013. File No. 001-35211).

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Exhibit Number	Description
2.2**	Amendment to Purchase and Sale Agreement, dated as of June 7, 2013, by and among Chesapeake Exploration, L.L.C., Arcadia Resources, L.P., Jamestown Resources, L.L.C., Larchmont Resources, L.L.C. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on June 12, 2013. File No. 001-35211).
2.3**	Purchase and Sale Agreement, dated April 19, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.2 of the Quarterly Report on Form 10-Q filed with the SEC on May 2, 2013. File No. 001-35211).
2.4	First Amendment of Purchase and Sale Agreement, dated as of June 11, 2013 but effective as of June 5, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.2 of the Current Report on Form 8-K filed with the SEC on June 12, 2013. File No. 001-35211).
2.5	Second Amendment of Purchase and Sale Agreement, dated as of June 27, 2013 but effective as of June 5, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on July 3, 2013. File No. 001-35211).
2.6	Third Amendment of Purchase and Sale Agreement, dated as of July 11, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on July 17, 2013. File No. 001-35211).
2.7	Fourth Amendment of Purchase and Sale Agreement, dated as of July 31, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on August 6, 2013. File No. 001-35211).
2.8	Fifth Amendment of Purchase and Sale Agreement, dated as of August 29, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on September 3, 2013. File No. 001-35211).
2.9	Sixth Amendment of Purchase and Sale Agreement, dated as of September 20, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on September 23, 2013. File No. 001-35211).
2.10	Letter Agreement to Purchase and Sale Agreement, dated September 30, 2013, by and among Gastar Exploration Texas, LP, Gastar Exploration USA, Inc. and Cubic Energy, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on October 4, 2013. File No. 001-35211).
2.11	Purchase and Sale Agreement, dated as of July 2, 2013, by and among Newfield Exploration Mid-Continent Inc. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on August 12, 2013. File No. 001-35211).

2.12**	Agreement of Sale and Purchase, dated September 4, 2013, by and among Gastar Exploration USA, Inc., Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
2.13	Amended and Restated Plan of Arrangement Under Section 193 of the Business Corporations Act (Alberta), effective as of November 14, 2013 (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on November 15, 2013. File No. 001-32714).
2.14	Agreement and Plan of Merger, dated as of January 31, 2014, among Gastar Exploration, Inc. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
3.1	Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.2	Second Amended and Restated Bylaws of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.2 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.3	Certificate of Merger (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).

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Exhibit Number	Description
3.4	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).
3.5	Certificate of Designation of Rights and Preferences of 10.75% Series B Cumulative Preferred Stock (incorporated by reference to Exhibit 3.4 of the Form 8-A filed with the SEC on November 1, 2013. File No. 001-35211).
4.1	Indenture, dated as of May 15, 2013, among Gastar Exploration USA, Inc., the Subsidiary Guarantors (as defined therein) and Wells Fargo Bank, National Association, and any and all successors thereto, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 of the Current Report on Form 8-K filed with the SEC on May 15, 2013. File No. 001-35211).
4.2	Form of 8 5/8% Senior Secured Notes due 2018 (incorporated by reference to Exhibit A to Exhibit 4.1 of the Current Report on Form 8-K filed with the SEC on May 15, 2013. File No. 001-35211).
4.3	Registration Rights Agreement dated as of May 15, 2013, by and among Gastar Exploration USA, Inc., the Guarantors signatory thereto, and Imperial Capital, LLC, Iberia Capital Partners L.L.C. and Tudor, Pickering, Holt & Co. Securities, Inc. (incorporated by reference to Exhibit 4.3 of the Current Report on Form 8-K filed with the SEC on May 15, 2013. File No. 001-35211).
4.4	Registration Rights Agreement dated as of November 15, 2013, by and among Gastar Exploration USA, Inc., the Guarantors signatory thereto, and Imperial Capital LLC, Credit Suisse Securities (USA) LLC, Iberia Capital Partners L.L.C. and Sterne, Agee & Leach, Inc. (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on November 20, 2013 (File No. 001-35211).
10.1	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 Quarterly Report on Form 10-Q filed with the SEC on November 7, 2012. File No. 001-32714).
10.2	Intercreditor Agreement, dated as of June 7, 2013, among Gastar Exploration USA, Inc., certain subsidiaries party thereto, Wells Fargo Bank, National Association, as First Priority Agent and Wells Fargo Bank, National Association, as Second Priority Agent (incorporated by reference to Exhibit 10.2 of the Current Report on Form 8-K filed with the SEC on June 12, 2013. File No. 001-35211).
10.3	Second Amended and Restated Credit Agreement, dated as of June 7, 2013, among Gastar Exploration USA, Inc., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and Issuing Lender, and the Lenders named therein (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on June 12, 2013. File No. 001-35211).
10.4	Waiver, Agreement and Amendment No. 1 to Second Amended and Restated Credit Agreement, dated as of July 31, 2013, among Gastar Exploration USA, Inc., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and Issuing Lender, and the Lenders named therein (incorporated by reference to Exhibit 10.3 of the Quarterly

	Report on Form 10-Q filed with the SEC on August 5, 2013. File No. 001-35211).
10.5	Agreement and Amendment No. 2 to Second Amended and Restated Credit Agreement, dated as of October 18, 2013, among Gastar Exploration USA, Inc., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and Issuing Lender, and the Lenders named therein (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on October 22, 2013. File No. 001-35211).
10.6	Form of the Final Settlement Agreement between Chesapeake Exploration, L.L.C., Chesapeake Energy Corporation, Gastar Exploration Ltd., Gastar Exploration Texas, LP and Gastar Exploration Texas, LLC, effective March 28, 2013 (incorporated by reference to Exhibit 10.1 of the Quarterly Report on Form 10-Q filed with the SEC on May 2, 2013. File No. 001-35211).
10.7	First Lien Guaranty Agreement, dated as of December 18, 2013, between Gastar Exploration, Inc. and Wells Fargo Bank, National Association, as Collateral Agent (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on December 24, 2013. File No. 001-35211).
10.8	Parent Guarantee, dated as of December 23, 2013, of Gastar Exploration, Inc. (incorporated by reference to Exhibit 10.2 of the Current Report on Form 10-K filed with the SEC on December 24, 2013. File No. 001-35211).

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Exhibit Number	Description
10.9	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 by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the SEC on July 6, 2009. File No. 001-32714).
10.10	Purchase and Sale Agreement, dated September 21, 2010, by and between Gastar Exploration USA, Inc. and Atinum Marcellus I LLC (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on September 24, 2010. File No. 001-32714).
10.11	Form of Participation Agreement (incorporated by reference to Exhibit 2.2 of the Current Report on Form 8-K filed with the SEC on September 24, 2010. File No. 001-32714).
10.12	Guarantee Agreement, dated November 7, 2013, by and between Gastar Exploration Ltd. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on November 7, 2013. File No. 001-35211).
10.13*	Employment Agreement dated March 23, 2005 by and among First Sourcenergy Wyoming, Inc., Gastar Exploration Ltd. and J. Russell Porter (incorporated by reference to Exhibit 10.2 of the Registration Statement on Form S-1, filed with the SEC on August 12, 2005. Registration No. 333-127498).
10.14*	First Amendment to Employment Agreement entered into by and between Gastar Exploration, Ltd, Gastar Exploration USA, Inc., f/k/a First Sourcenergy Wyoming, Inc., and J. Russell Porter as of July 25, 2008 (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on July 28, 2008. File No. 001-32714).
10.15*	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 Current Report on Form 8-K filed with the SEC on February 7, 2011. File No. 001-32714).
10.16*	Employment Agreement dated April 26, 2005 by and among First Sourcenergy Wyoming, Inc., Gastar Exploration Ltd. and Michael A Gerlich (incorporated by reference to Exhibit 10.3 of the Registration Statement on Form S-1, filed with the SEC on August 12, 2005. Registration No. 333-127498).
10.17*	First Amendment to Employment Agreement entered into by and between Gastar Exploration, Ltd, Gastar Exploration USA, Inc., f/k/a First Sourcenergy Wyoming, Inc., and Michael A. Gerlich as of July 25, 2008 (incorporated by reference to Exhibit 10.2 of the Current Report on Form 8-K filed with the SEC on July 28, 2008. File No. 001-32714).
10.18*	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 Current Report on Form 8-K filed with the SEC on April 12, 2012. File No. 001-32714).
10.19*	Form of Gastar officer stock option grant (incorporated by reference to Exhibit 10.10 of the Annual Report on Form 10-K for the fiscal year ended December 31, 2005 filed with the SEC on March 31,

	2006. File No. 001-32714).
10.20*	Gastar Exploration Inc. 2006 Long-Term Stock Incentive Plan approved June 1, 2006 (incorporated by reference to Exhibit 10.11 of the Quarterly Report on Form 10-Q filed with the SEC on August 14, 2006. File No. 001-32714).
10.21*	Gastar Exploration Inc. Long-Term Incentive Plan, adopted January 31, 2014 (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
10.22*	First Amendment to Gastar Exploration Inc. 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 Current Report on Form 8-K filed with the SEC on June 10, 2009. File No. 001-32714).
10.23*	Second Amendment to Gastar Exploration Inc. 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on June 18, 2012. File No. 001-32714).
10.24*	Form of Indemnity Agreement for Directors and Certain Executive Officers (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on December 19, 2006. File No. 001-32714).
10.25*	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 by reference to Exhibit 10.18 of the Annual Report on Form 10-K for the fiscal year ended December 31, 2007, filed with the SEC on March 17, 2008. File No. 001-32714).

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Exhibit Number	Description
10.26*	First Amendment to Gastar Exploration Ltd. Employee Change of Control Severance Plan, dated April 11, 2012 (incorporated by reference to Exhibit 10.2 of the Current Report on Form 8-K filed with the SEC on April 12, 2012. File No. 001-32714).
10.27*†	Second Amendment to Gastar Exploration Inc. Employee Change of Control Severance Plan, dated March 12, 2014.
10.28*	Gastar Exploration Ltd. Annual Bonus Plan (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on August 8, 2011. File No. 001-32714).
10.29*	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 of the Registration Statement on Form S-8 filed with the SEC on December 4, 2006. File No. 333-139112).
10.30†	Settlement Agreement, dated March 12, 2014, by Gastar Exploration Inc., Kleinheinz Capital Partners, Inc., Global Undervalued Securities Master Fund, L.P., John B. Kleinheinz and Fred N. Reynolds
12.1†	Computation of Ratio of Earnings to Fixed Charges
12.2†	Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends
21.1†	Subsidiaries of Gastar Exploration Inc.
23.1†	Consent of BDO USA, LLP
23.2†	Consent of BDO USA, LLP
23.3†	Consent of Wright & Company, Inc.
31.1†	Certification of Chief Executive Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of Chief Financial Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1††	Certification of Chief Executive Officer and Chief Financial Officer of Gastar Exploration Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1††	Report of Wright & Company, Inc. dated January 17, 2014.
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.
**	Pursuant to Item 601(b)(2) of Regulation S-K, the schedules and similar attachments have not been filed. The registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commisssion upon request.
†	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.

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GASTAR EXPLORATION INC.

/s/ J. RUSSELL PORTER
J. Russell Porter, President and Chief
Executive Officer
(Duly authorized officer and principal
executive officer)
March 13, 2014

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 13, 2014
/s/ MICHAEL A. GERLICH Michael A. Gerlich	Senior Vice President, Chief Financial Officer and Corporate Secretary (principal financial and accounting officer)	March 13, 2014
/s/ JOHN M. SELSER SR. John M. Selser Sr.	Chairman of the Board	March 13, 2014
/s/ JOHN H. CASSELS John H. Cassels	Director	March 13, 2014
/s/ RANDOLPH C. COLEY Randolph C. Coley	Director	March 13, 2014
/s/ ROBERT D. PENNER Robert D. Penner	Director	March 13, 2014

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GASTAR EXPLORATION, INC. AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gastar Exploration, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Gastar Exploration, Inc. (the "Company") and subsidiaries as of December 31, 2013 and 2012 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. 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 the Company at December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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), the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 13, 2014 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
March 13, 2014

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Report of Independent Registered Public Accounting Firm
Board of Directors and Stockholders
Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.)
Houston, Texas

We have audited the accompanying consolidated balance sheets of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc. ("Gastar USA")) and subsidiaries as of December 31, 2013 and 2012 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. 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 USA at December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO USA, LLP
Dallas, Texas
March 13, 2014

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GASTAR EXPLORATION, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	2012
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$32,393	$8,901
Accounts receivable, net of allowance for doubtful accounts of $507 and $546, respectively	21,656	9,540
Commodity derivative contracts	—	7,799
Prepaid expenses	1,145	1,097
Total current assets	55,194	27,337
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	96,220	67,892
Proved properties	935,773	671,193
Total oil and natural gas properties	1,031,993	739,085
Furniture and equipment	2,691	1,925
Total property, plant and equipment	1,034,684	741,010
Accumulated depreciation, depletion and amortization	(517,171)	(484,759)
Total property, plant and equipment, net	517,513	256,251
OTHER ASSETS:		
Commodity derivative contracts	7,545	1,369
Deferred charges, net	2,950	836
Advances to operators and other assets	6,733	4,275
Total other assets	17,228	6,480
TOTAL ASSETS	$589,935	$290,068
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$11,046	$23,863
Revenue payable	12,514	8,801
Accrued interest	3,504	151
Accrued drilling and operating costs	8,756	3,907
Advances from non-operators	9,259	17,540
Commodity derivative contracts	3,403	1,399
Commodity derivative premium payable	145	—
Asset retirement obligation	633	358
Other accrued liabilities	4,844	1,493
Total current liabilities	54,104	57,512
LONG-TERM LIABILITIES:		
Long-term debt	312,994	98,000
Commodity derivative contracts	378	1,304
Commodity derivative premium payable	7,000	—
Asset retirement obligation	5,430	6,605
Other long-term liabilities	—	111
Total long-term liabilities	325,802	106,020

Commitments and contingencies (Note 14)		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 275,000,000 shares authorized; 61,211,658 and 66,432,609 shares issued and outstanding at December 31, 2013 and 2012, respectively; no par value at December 31, 2012	61	316,346
Additional paid-in capital	337,969	28,336
Accumulated deficit	(254,823)	(294,787)
Total stockholders' equity	83,207	49,895
Non-controlling interest:		
Preferred stock of subsidiary, aggregate liquidation preference $152,454 and $98,781 at December 31, 2013 and 2012, respectively	126,822	76,641
Total equity	210,029	126,536
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$589,935	$290,068

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

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GASTAR EXPLORATION, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands, except share and per share data)		
REVENUES:			
Natural gas	$40,416	$23,318	$23,523
Oil and condensate	36,480	11,570	3,416
NGLs	15,611	7,630	1,092
Total natural gas, oil and condensate and NGLs revenues	92,507	42,518	28,031
(Loss) gain on commodity derivatives contracts	(4,752)	7,422	12,204
Total revenues	87,755	49,940	40,235
EXPENSES:			
Production taxes	4,651	2,269	620
Lease operating expenses	9,456	6,174	8,630
Transportation, treating and gathering	4,006	4,965	4,501
Depreciation, depletion and amortization	32,449	25,424	15,216
Impairment of natural gas and oil properties	—	150,787	—
Accretion of asset retirement obligation	468	388	534
General and administrative expense	16,961	12,211	11,365
Litigation settlement expense	1,000	1,250	—
Total expenses	68,991	203,468	40,866
INCOME (LOSS) FROM OPERATIONS	18,764	(153,528)	(631)
OTHER INCOME (EXPENSE):			
Gain on acquisition of assets at fair value	27,670	—	—
Interest expense	(13,168)	(270)	(113)
Investment and other income	48	9	10
Foreign transaction loss	(14)	(2)	(6)
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES	33,300	(153,791)	(740)
Income tax benefit	(16,042)	—	—
NET INCOME (LOSS)	49,342	(153,791)	(740)
Dividends on preferred stock attributable to non-controlling interest	(9,378)	(7,077)	(1,024)
NET INCOME (LOSS) ATTRIBUTABLE TO GASTAR EXPLORATION, INC.	$39,964	$(160,868)	$(1,764)
NET INCOME (LOSS) PER SHARE OF COMMON STOCK ATTRIBUTABLE TO GASTAR EXPLORATION, INC. COMMON STOCKHOLDERS:			
Basic	$0.66	$(2.53)	$(0.03)
Diluted	$0.63	$(2.53)	$(0.03)
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:			
Basic	60,220,115	63,538,362	63,003,579
Diluted	63,618,401	63,538,362	63,003,579

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

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

	Common Stock						
	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Total Gastar Exploration, Inc. Stockholders' Equity	Non-controlling Interest	Total Equity
	(in thousands, except share data)						
Balance at December 31, 2010	64,179,115	$316,346	$23,200	$(132,155)	$207,391	$ —	$207,391
Issuance of restricted stock, 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 stock, 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
Repurchase of shares of common stock	(6,781,768)	(9,753)	—	—	(9,753)	—	(9,753)
Reclassification of par value of common stock	—	(306,532)	306,532	—	—	—	—
Issuance of restricted stock, net of forfeitures	1,550,817	—	(334)	—	(334)	—	(334)
Exercise of stock options, net of forfeitures	10,000	—	—	—	—	—	—
Stock based compensation	—	—	3,435	—	3,435	—	3,435
Net income	—	—	—	39,964	39,964	—	39,964
Issuance of preferred stock of subsidiary	—	—	—	—	—	50,181	50,181
Balance at December 31, 2013	61,211,658	$61	$337,969	$(254,823)	$83,207	$ 126,822	$210,029

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

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

	For the years ended December 31,		
	2013	2012	2011
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$49,342	$(153,791)	$(740)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	32,449	25,424	15,216
Impairment of natural gas and oil properties	—	150,787	—
Stock-based compensation	3,435	3,295	2,612
Mark to market of commodity derivatives contracts:			
Total loss (gain) on commodity derivatives contracts	4,752	(7,422)	(12,204)
Cash settlements of matured commodity derivative contracts, net	5,892	16,251	11,449
Cash premiums paid for commodity derivatives contracts	(152)	(4,539)	(3,370)
Amortization of deferred financing costs	2,322	224	249
Accretion of asset retirement obligation	468	388	534
Settlement of asset retirement obligation	(66)	(636)	—
Gain on acquisition of assets at fair value	(27,670)	—	—
Deferred tax benefit	(16,042)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(8,431)	2,487	(6,672)
Prepaid expenses	(48)	146	(100)
Accounts payable and accrued liabilities	1,563	4,441	4,303
Net cash provided by operating activities	47,814	37,055	11,277
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development and purchase of oil and natural gas properties	(95,343)	(136,311)	(73,718)
Advances to operators	(22,213)	(9,649)	(8,392)
Acquisition of oil and natural gas properties	(251,096)	—	—
Proceeds from sale of oil and natural gas properties	112,201	—	—
(Use of proceeds) proceeds from non-operators	(8,281)	(1,983)	18,740
Purchase of furniture and equipment	(766)	(296)	(454)
Net cash used in investing activities	(265,498)	(148,239)	(63,824)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repurchase of common stock	(9,753)	—	—
Proceeds from revolving credit facility	19,000	98,000	71,000
Repayment of revolving credit facility	(117,000)	(30,000)	(41,000)
Proceeds from issuance of senior secured notes, net of discount	312,279	—	—
Proceeds from issuance of preferred stock, net of issuance costs	50,183	49,250	27,391
Dividends on preferred stock attributable to non-controlling interest	(9,378)	(7,077)	(1,024)
Deferred financing charges	(3,785)	(450)	(276)
Other	(370)	(285)	(336)
Net cash provided by financing activities	241,176	109,438	55,755
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	23,492	(1,746)	3,208
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	8,901	10,647	7,439
CASH AND CASH EQUIVALENTS, END OF PERIOD	$32,393	$8,901	$10,647

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

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GASTAR EXPLORATION INC. (FORMERLY KNOWN AS GASTAR EXPLORATION USA, INC.) AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

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	December 31, 2013	2012
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$32,379	$8,892
Accounts receivable, net of allowance for doubtful accounts of $507 and $546, respectively	21,650	9,539
Commodity derivative contracts	—	7,799
Prepaid expenses	946	919
Total current assets	54,975	27,149
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	96,220	67,892
Proved properties	935,765	671,185
Total natural gas and oil properties	1,031,985	739,077
Furniture and equipment	2,691	1,925
Total property, plant and equipment	1,034,676	741,002
Accumulated depreciation, depletion and amortization	(517,164)	(484,752)
Total property, plant and equipment, net	517,512	256,250
OTHER ASSETS:		
Commodity derivative contracts	7,545	1,369
Deferred charges, net	2,950	836
Advances to operators and other assets	6,733	4,275
Total other assets	17,228	6,480
TOTAL ASSETS	$589,715	$289,879
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$11,031	$23,863
Revenue payable	12,514	8,801
Accrued interest	3,504	151
Accrued drilling and operating costs	8,756	3,907
Advances from non-operators	9,259	17,540
Commodity derivative contracts	3,403	1,399
Commodity derivative premium payable	145	—
Asset retirement obligation	633	358
Other accrued liabilities	4,794	1,480
Total current liabilities	54,039	57,499
LONG-TERM LIABILITIES:		
Long-term debt	312,994	98,000
Commodity derivative contracts	378	1,304
Commodity derivative premium payable	7,000	—
Asset retirement obligation	5,423	6,598
Due to parent	34,337	30,903
Other long-term liabilities	—	111
Total long-term liabilities	360,132	136,916
Commitments and contingencies (Note 14)		
STOCKHOLDERS' EQUITY:		

Preferred stock, 40,000,000 shares authorized		
Series A Preferred stock, $0.01 par value; 10,000,000 shares authorized; 3,958,160 and 3,951,254 shares issued and outstanding at December 31, 2013 and 2012, respectively, with liquidation preference of $25.00 per share	40	40
Series B Preferred stock, $0.01 par value; 10,000,000 shares authorized; 2,140,000 shares issued and outstanding at December 31, 2013, with liquidation preference of $25.00 per share	21	—
Common stock, $0.001 par value; 275,000,000 shares authorized; 750 shares issued and outstanding at December 31, 2013 and 2012, respectively; no par value at December 31, 2012	—	237,431
Additional paid-in capital	352,192	76,601
Accumulated deficit	(176,709)	(218,608)
Total stockholders' equity	175,544	95,464
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$589,715	$289,879

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

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GASTAR EXPLORATION INC. (FORMERLY KNOWN AS GASTAR EXPLORATION USA, INC.) AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2013	2012	2011
	(in thousands, except share and per share data)		
REVENUES:			
Natural gas	$40,416	$23,318	$23,523
Oil and condensate	36,480	11,570	3,416
NGLs	15,611	7,630	1,092
Total natural gas, oil and condensate and NGLs revenues	92,507	42,518	28,031
(Loss) gain on commodity derivative contracts	(4,752)	7,422	12,204
Total revenues	87,755	49,940	40,235
EXPENSES:			
Production taxes	4,651	2,269	620
Lease operating expenses	9,456	6,174	8,629
Transportation, treating and gathering	4,006	4,965	4,501
Depreciation, depletion and amortization	32,449	25,424	15,216
Impairment of natural gas and oil properties	—	150,787	—
Accretion of asset retirement obligation	468	388	534
General and administrative expense	15,153	10,732	10,434
Litigation settlement expense	1,000	1,250	—
Total expenses	67,183	201,989	39,934
INCOME (LOSS) FROM OPERATIONS	20,572	(152,049)	301
OTHER INCOME (EXPENSE):			
Gain on acquisition of assets at fair value	27,670	—	—
Interest expense	(13,016)	(271)	(112)
Investment and other income (expense)	20	(4)	95
Foreign transaction (loss) gain	(11)	2	1
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES	35,235	(152,322)	285
Income tax benefit	(16,042)	—	—
NET INCOME (LOSS)	51,277	(152,322)	285
Dividends on preferred stock	(9,378)	(7,077)	(1,024)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDER	$41,899	$(159,399)	$(739)

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

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GASTAR EXPLORATION INC. (FORMERLY KNOWN AS GASTAR EXPLORATION USA, INC.) AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Stockholder's Equity
	Shares	Amount	Shares	Amount	Shares	Amount			
	(in thousands, except share data)								
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
Distribution to Parent	—	—	—	—	—	(12,000)	—	—	(12,000)
Reclassification of par value of common stock	—	—	—	—	—	(225,431)	225,431	—	—
Issuance of preferred stock	6,906	—	2,140,000	21	—	—	50,160	—	50,181
Preferred stock dividends	—	—	—	—	—	—	—	(9,378)	(9,378)
Net income	—	—	—	—	—	—	—	51,277	51,277
Balance at December 31, 2013	3,958,160	$40	2,140,000	$21	750	$—	$352,192	$ (176,709)	$ 175,544

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

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GASTAR EXPLORATION INC. (FORMERLY KNOWN AS GASTAR EXPLORATION USA, INC.) AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31,		
	2013	2012	2011
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$51,277	$(152,322)	$285
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	32,449	25,424	15,216
Impairment of natural gas and oil properties	—	150,787	—
Stock-based compensation	3,435	3,295	2,612
Mark to market of commodity derivatives contracts:			
Total loss (gain) on commodity derivatives contracts	4,752	(7,422)	(12,204)
Cash settlements of matured commodity derivatives contracts	5,892	16,251	11,449
Cash premiums paid for commodity derivatives contracts	(152)	(4,539)	(3,370)
Amortization of deferred financing costs	2,322	224	249
Accretion of asset retirement obligation	468	388	534
Settlement of asset retirement obligation	(66)	(636)	—
Gain on acquisition of assets at fair value	(27,670)	—	—
Deferred tax benefit	(16,042)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(8,426)	2,485	(6,669)
Prepaid expenses	(27)	169	(137)
Accounts payable and accrued liabilities	1,571	4,508	4,236
Net cash provided by operating activities	49,783	38,612	12,201
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development and purchase of oil and natural gas properties	(95,343)	(136,311)	(73,718)
Advances to operators	(22,213)	(9,649)	(8,392)
Acquisition of oil and natural gas properties	(251,096)	—	—
Proceeds from sale of oil and natural gas properties	112,201	—	—
(Use of proceeds) proceeds from non-operators	(8,281)	(1,983)	18,740
Purchase of furniture and equipment	(766)	(296)	(454)
Net cash used in investing activities	(265,498)	(148,239)	(63,824)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility	19,000	98,000	71,000
Repayment of revolving credit facility	(117,000)	(30,000)	(41,000)
Proceeds from issuance of senior secured notes, net of discount	312,279	—	—
Proceeds from issuance of preferred stock, net of issuance costs	50,183	49,250	27,391
Dividends on preferred stock	(9,378)	(7,077)	(1,024)
Deferred financing charges	(3,785)	(450)	(276)
Distribution to Parent, net	(12,061)	(1,824)	(1,374)
Other	(36)	25	100
Net cash provided by financing activities	239,202	107,924	54,817
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	23,487	(1,703)	3,194
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	8,892	10,595	7,401
CASH AND CASH EQUIVALENTS, END OF PERIOD	$32,379	$8,892	$10,595

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

GASTAR EXPLORATION, INC. (FORMERLY GASTAR EXPLORATION LTD.) AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Gastar Exploration, Inc., formerly known as Gastar Exploration Ltd., is an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the United States ("U.S."). Gastar Exploration, Inc.'s principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. Gastar Exploration, Inc. is currently pursuing development within the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play in Oklahoma and the development of liquids-rich natural gas in the Marcellus Shale and Utica Shale plays in West Virginia. Gastar Exploration, Inc. also holds prospective Marcellus Shale acreage in Pennsylvania. Gastar Exploration, Inc. sold substantially all of its East Texas assets on October 2, 2013, with an effective date of January 1, 2013.

On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation, changed its jurisdiction of incorporation to the State of Delaware and changed its name to "Gastar Exploration, Inc." At December 31, 2013, Gastar Exploration, Inc. was a holding company and substantially all of its operations were conducted through, and substantially all of its assets were held by, its primary operating subsidiary, Gastar Exploration USA, Inc. and its wholly-owned subsidiaries. Subsequently, on January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar Exploration USA, Inc. as part of a reorganization to eliminate the holding company corporate structure. Pursuant to the merger agreement, shares of the Gastar Exploration Inc.'s common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to "Gastar Exploration Inc." Gastar Exploration Inc., together with its subsidiaries, owns and will continue to conduct business in substantially the same manner as was being conducted by Gastar Exploration, Inc. and its subsidiaries prior to the merger. Unless otherwise stated or the context requires otherwise, all references in these notes to "Gastar USA" refer collectively to Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) and its wholly-owned subsidiaries, all references to "Parent" refer solely to Gastar Exploration, Inc. (formerly known as Gastar Exploration Ltd.), and all references to "Gastar," the "Company" and similar terms refer collectively to Gastar Exploration, Inc. 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, as predecessors to Gastar Exploration Inc., in satisfaction of Rule 12g-3(g) of the Securities Exchange Act of 1934. 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 18, "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.

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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.
Use of estimates in Preparation of Financial Statements
The preparation of the consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. 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. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its 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 the Company’s financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes including uncertain tax positions, the outcome of pending litigation, stock-based compensation, valuation of commodity derivatives contracts, future development and abandonment costs, estimates related to certain oil, condensate , natural gas and NGLs revenues and operating expenses, and the estimates of proved oil, condensate, natural gas and NGLs reserve quantities that are used to calculate depletion and impairment of proved oil and natural gas properties.
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 $32.4 million and $8.9 million as of December 31, 2013 and 2012, 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,		
	2013	2012	2011
	(in thousands)		
Allowance for doubtful accounts, beginning of year	$546	$551	$571
Expense	—	—	—
Reductions/write-offs	(39)	(5)	(20)
Allowance for doubtful accounts, end of year	$507	$546	$551

Oil and Natural Gas Properties
The Company follows the full cost method of accounting for oil and natural gas operations, whereby all costs incurred in the acquisition, exploration and development of oil and natural gas 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,

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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 oil and natural gas 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 oil and natural gas 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 oil and natural gas properties and as additional depletion expense. Proceeds from a sale of oil and natural gas 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 oil, condensate, natural gas and NGLs that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. As discussed below, the estimate of the Company's proved reserves as of December 31, 2013 and 2012 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. 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 oil, condensate, natural gas 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.

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.

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.

Capitalized Interest

The Company capitalizes interest on assets not being amortized related to specific projects such as its drilling in progress and unproven oil and natural gas 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, 2013 was the Notes. Currently, the Company only capitalizes interest on the Notes. 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 $3.3 million, $1.9 million and $818,000 for 2013, 2012 and 2011, respectively.

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, 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.

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,	
	2013	2012
Deferred charges	$3,269	$2,525
Accumulated amortization	(319)	(1,689)
Deferred charges, net	$2,950	$836

Derivative Instruments and Hedging Activity

The Company uses derivative instruments in the form of commodity 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 oil, condensate, natural gas and NGLs associated with future 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 total revenue within the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities. See Note 7, “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 (loss) gain on commodity derivatives contracts within the Company’s consolidated statements of operations. Gains or losses from the settlement of matured commodity derivatives contracts are included in (loss) gain on commodity derivatives contracts in the Company’s consolidated statement of operations.

Stock-Based Compensation

The Company reports compensation expense for restricted common stock, performance based units (“PBUs”) and stock options 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.

Stock-based compensation cost for restricted shares is estimated at the grant date based on the award's fair value, which is equal to the prior day's closing stock price. Such fair value is recognized as expense over the requisite service period. Stock-based compensation cost for PBUs is estimated at the grant based on the award's fair value, which is calculated using a Monte Carlo Simulation model. The Monte Carlo Simulation model uses a stochastic process to create a range of potential future outcomes given a variety of inputs, including expected future stock price based on predictive assumptions of volatility, risk free rate, random numbers, the current stock price and forecast period. Such fair value is recognized as expense over the requisite service period. 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. The Company did not award any stock option grants during 2013, 2012 or 2011.

Treasury Stock

Treasury stock purchases are recorded at cost as a reduction to common stock. Shares of common stock are canceled upon repurchase.

Revenue Recognition

The Company uses the sales method of accounting for the sale of its oil, condensate, natural gas 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 oil, condensate, natural gas 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, 2013 and 2012.

The Company records its share of revenues based on production volumes and contracted sales prices. The sales price for oil, condensate, natural gas 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, oil, condensate, natural gas and NGLs volumes sold are not significantly different from the Company's share of production.

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

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 oil, condensate, natural gas 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

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

Joint Venture Operations

The majority of the Company's oil and natural gas 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.

Foreign Currency Exchange

The consolidated financial statements of the Company are presented in U.S. dollars. The functional currency for the Company 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.

All 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. The Company owns non-operating working interests in two gas wells located in Alberta, Canada, from which it has received no revenue since January 1, 2012.

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.

Recent Accounting Developments

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

Income taxes. In July 2013, the FASB issued an amendment to previously issued guidance regarding the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The amendment requires that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward, except as follows. To the extent a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The assessment of whether a deferred tax asset is available is based on the unrecognized tax benefit and deferred tax asset that exist at the reporting date and should be made presuming disallowance of the tax position at the reporting date. This amendment does not require new recurring disclosures. This guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Earlier application is permitted. The adoption of this guidance is not expected to impact our operating results, financial position or cash flows upon adoption.

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3. Property, Plant and Equipment

The amount capitalized as oil and natural gas properties was incurred for the purchase and development of various properties in the U.S., specifically the states of West Virginia, Pennsylvania, Oklahoma, Texas, Wyoming and Montana. The Company sold substantially all of its interest in East Texas on October 2, 2013, with an effective date of January 1, 2013. 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, with an effective date of January 1, 2012. The Company's total property, plant and equipment consists of the following:

	December 31,	
	2013	2012
	(in thousands)	
Oil and natural gas properties, full cost method of accounting:		
Unproved properties	$96,220	$67,892
Proved properties	935,773	671,193
Total oil and natural gas properties	1,031,993	739,085
Furniture and equipment	2,691	1,925
Total property and equipment	1,034,684	741,010
Impairment of proved natural gas and oil properties	(337,939)	(337,939)
Accumulated depreciation, depletion and amortization	(179,232)	(146,820)
Total accumulated depreciation, depletion and amortization	(517,171)	(484,759)
Total property and equipment, net	$517,513	$256,251

Included in the Company's oil and natural gas properties are asset retirement costs of $3.4 million and $4.8 million as of December 31, 2013 and 2012, respectively.

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

	December 31,	
	2013	2012
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$4,774	$1,902
Acreage acquisition costs	86,097	62,395
Capitalized interest	5,349	3,595
Total unproved properties excluded from amortization	$96,220	$67,892

For the year ended December 31, 2013, management's evaluation of unproved properties resulted in an impairment. Due to continued lower natural gas prices for dry gas and no current plans to drill or extend leases in Marcellus East, the Company reclassified $20.5 million of unproved properties to proved properties for the year ended December 31, 2013. 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 oil and natural gas 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 oil, condensate, natural gas and NGLs reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage) to the extent not included in oil and natural gas 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

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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:

	2013				
	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu) (1)		$3.67	$3.61	$3.44	$2.95
West Texas Intermediate oil price (per Bbl) (1)		$96.78	$91.69	$88.13	$89.17
Impairment recorded (pre-tax) (in thousands)	$—	$—	$—	$—	$—
	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)	$—	$—	$—	$—	$—

(1) For the respective periods, oil and natural gas 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 oil, condensate, natural gas and NGLs prices could result in the recognition of future ceiling impairments.

Chesapeake Acquisition

On March 28, 2013, Gastar USA entered into a Purchase and Sale Agreement by and among Chesapeake Exploration, L.L.C., Arcadia Resources, L.P., Jamestown Resources, L.L.C., Larchmont Resources, L.L.C. (together, the “Chesapeake Parties”) and Gastar USA (the “Chesapeake Purchase Agreement”). Pursuant to the Chesapeake Purchase Agreement, Gastar USA was to acquire approximately 157,000 net acres of Oklahoma oil and gas leasehold interests from the Chesapeake Parties, including production from interests in 206 producing wells located in Oklahoma (the “Chesapeake Assets”). The Chesapeake Purchase Agreement contained customary representations and warranties and covenants, including provisions for indemnification, subject to the limitations described in the Chesapeake Purchase Agreement. On June 7, 2013, the parties to the Chesapeake Purchase Agreement entered into an Amendment to Purchase and Sale Agreement, dated June 7, 2013, in order to revise the description of the properties to be acquired and to evidence the withdrawal of Arcadia Resources, L.P. and Jamestown Resources, L.L.C. from the Chesapeake Purchase Agreement. Pursuant to the Chesapeake Purchase Agreement, as amended, on June 7, 2013, Gastar USA completed the acquisition of the Chesapeake Assets for a final adjusted purchase price of $69.4 million, reflecting adjustment for an acquisition effective date of October 1, 2012.

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Upon completion of the initial purchase price allocation, as of June 7, 2013, the Company reviewed and verified its assessment, including the identification and valuation of assets acquired. The Company accounted for the acquisition as a business combination and therefore, recorded the assets acquired at their estimated acquisition date fair values. The Company incurred $2.1 million of transaction and integration costs associated with the acquisition and expensed these costs as incurred as general and administrative expenses. The Company utilized relevant market assumptions to determine fair value and allocate the purchase price, such as future commodity prices, projections of estimated natural gas and oil reserves, expectations for future development and operating costs, projections of future rates of production, expected recovery rates and market multiples for similar transactions. Many of the assumptions used are unobservable and as such, represent Level 3 inputs under the fair value hierarchy as described in Note 6, “Fair Value Measurements.” The Company's preliminary assessment of the fair value of the Chesapeake Assets resulted in a fair market valuation of $113.1 million. With the completion of the asset valuation during the fourth quarter of 2013, the Company recorded the deferred tax attributes associated with the transaction. As a result of incorporating the final valuation information into the purchase price allocation, a bargain purchase gain of $27.7 million was recognized in the accompanying consolidated statements of operations. The bargain purchase gain was primarily attributable to the non-strategic nature of the divestiture to the seller, coupled with favorable economic trends in the industry and the geographic region in which the Chesapeake Assets are located. The Company believes the estimates used in the fair market valuation and purchase price allocation are reasonable and that the significant effects of the acquisition are properly reflected.
The following table summarizes the fair value of the assets acquired and liabilities assumed in connection with the Chesapeake Acquisition (in thousands):

Consideration:	
Cash consideration	$ 69,371
Fair Value of Liabilities Assumed:	
Deferred tax liability	16,042
Total purchase price plus liabilities assumed	$ 85,413
Estimated Fair Value of Assets Acquired:	
Unproved properties	$ 86,327
Proved properties	26,756
Total assets acquired	$ 113,083
Bargain purchase gain	$ 27,670

Hunton Joint Venture AMI Election

Effective July 1, 2013, Gastar USA's working interest partner in its original AMI in Oklahoma exercised its rights to acquire approximately 12,800 net acres and certain proved properties that Gastar USA acquired pursuant to the Chesapeake Purchase Agreement for a total payment of $11.8 million, of which $133,000 was deemed to be a reimbursement of transaction and integration costs associated with the acquisition and was recorded as a reduction of general and administrative expense.

Hunton Divestiture

On July 2, 2013, Gastar USA entered into a purchase and sale agreement with Newfield Exploration Mid-Continent Inc. (“Newfield”), dated July 2, 2013, pursuant to which Newfield acquired approximately 76,000 net undeveloped acres of oil and gas leasehold interests in Kingfisher and Canadian Counties, Oklahoma from Gastar USA and Gastar USA acquired approximately 1,850 net acres of Oklahoma oil and gas leasehold interests from Newfield. The transaction closed on August 6, 2013 for a net cash purchase price of approximately $57.0 million, adjusted for an acquisition effective date of May 1, 2013. The Company did not record a gain or loss related to the divestiture as it was not significant to the full cost pool.

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WEHLU Acquisition

On September 4, 2013, Gastar USA entered into a Purchase and Sale Agreement, dated September 4, 2013, by and among Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. (the “Lime Rock Parties”) and Gastar USA (the “WEHLU Purchase Agreement”). Pursuant to the WEHLU Purchase Agreement, Gastar USA acquired a 98.3% working interest (80.5% net revenue interest) in 24,000 net acres of the West Edmond Hunton Lime Unit (“WEHLU”) located in Kingfisher, Logan and Oklahoma Counties, Oklahoma, all of which is held by production (“WEHLU Assets”). Pursuant to the WEHLU Purchase Agremeent, Gastar USA completed the acquisition of the WEHLU Assets on November 15, 2013 for an adjusted cash purchase price of $177.8 million, reflecting customary adjustments and adjustment for an acquisition effective date of August 1, 2013 (the “WEHLU Acquisition”).

The Company accounted for the acquisition as a business combination and therefore, recorded the assets acquired at their estimated acquisition date fair values. The Company incurred $286,000 of transaction and integration costs associated with the acquisition and expensed these costs as incurred as general and administrative expenses. The Company utilized relevant market assumptions to determine fair value and allocate the purchase price, such as future commodity prices, projections of estimated natural gas and oil reserves, expectations for future development and operating costs, projections of future rates of production, expected recovery rates and market multiples for similar transactions. Many of the assumptions used are unobservable and as such, represent Level 3 inputs under the fair value hierarchy as described in Note 6, “Fair Value Measurements.” The Company's preliminary assessment of the fair value of the WEHLU Assets resulted in a fair market valuation of $176.8 million. As the fair market valuation varied less than 1% from the purchase price allocation recorded, no adjustment was made to the purchase price allocation.

The following table summarizes the estimated fair value of the assets acquired in connection with the WEHLU Acquisition (in thousands):

Consideration:	
Cash consideration	$ 177,778
Estimated Fair Value of Assets Acquired:	
Unproved properties	$ 13,026
Proved properties	164,752
Total assets acquired	$ 177,778

Chesapeake and WEHLU Acquisition Pro Forma Operating Results

The following unaudited pro forma results for the years ended December 31, 2013 and 2012 show the effect on the Company's consolidated results of operations as if the Chesapeake and WEHLU Acquisitions had occurred at the beginning of each respective period presented. The pro forma results are the result of combining the statement of operations of the Company with the statements of revenues and direct operating expenses for the properties acquired from the Chesapeake and Lime Rock Parties adjusted for (1) the financing directly attributable to the acquisitions, (2) assumption of ARO liabilities and accretion expense for the properties acquired and (3) additional depreciation, depletion and amortization expense as a result of the Company's increased ownership in the acquired properties. The statements of revenues and direct operating expenses for the Chesapeake and WEHLU assets exclude all other historical expenses of the Chesapeake and Lime Rock Parties. As a result, certain estimates and judgments were made in preparing the pro forma adjustments.

	For the Years Ended December 31,	
	2013	2012
	(in thousands, except per share data)	
	(Unaudited)	
Revenues	$ 132,721	$ 97,760
Net Loss	$ (4,836)	$ (175,809)
Loss per share:		
Basic	$ (0.08)	$ (2.77)

Diluted	$(0.08)	$(2.77)

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The pro forma information above includes numerous assumptions, is presented for illustrative purposes only and may not be indicative of the future results or results of operations that would have actually occurred had the Chesapeake and WEHLU Acquisitions occurred as presented. Further, the above pro forma amounts do not consider any potential synergies or integration costs that may result from the transaction. In addition, future results may vary significantly from the results reflected in such pro forma information.

The amounts of revenues and revenues in excess of direct operating expenses included in the Company's consolidated statements of operations for the Chesapeake and WEHLU Acquisitions are shown in the table below. Direct operating expenses includes lease operating expenses and production taxes.

	Year Ended December 31, 2013
	(in thousands)
Revenues	$11,292
Excess of revenues over direct operating expenses	$7,591

Hilltop Area, East Texas Sale

On April 19, 2013, Gastar Exploration Texas, LP (“Gastar Texas”) and Gastar USA entered into a Purchase and Sale Agreement by and among Gastar Texas, Gastar USA and Cubic Energy, Inc. (“Cubic Energy”) (the “East Texas Sale Agreement”). Pursuant to the East Texas Sale Agreement, as amended, on October 2, 2013, Cubic Energy acquired from Gastar Texas approximately 31,800 gross (16,300 net) acres of leasehold interests in the Hilltop area of East Texas in Leon and Robertson Counties, Texas, including production from interests in producing wells, for net proceeds of approximately $42.9 million, reflecting adjustment for accounting effective date of January 1, 2013 and other customary adjustments. The Company did not record a gain or loss related to the divestiture as it was not significant to the full cost pool.

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 pursued an initial three-year development program that called 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 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. Due to continued natural gas price declines, Atinum and Gastar USA agreed to reduce the 2013 minimum wells to be drilled requirement to 19 wells which would result in 57 gross wells on production at December 31, 2013, compared to the 60 gross wells originally agreed upon. As of December 31, 2013, all 57 gross (27.0 net) wells were on production as agreed upon.

Subsequent to June 30, 2011, an AMI was established for additional acreage acquisitions in Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia. Within this AMI, Gastar USA acts as operator and is obligated to offer any future lease acquisitions within the AMI to Atinum on a 50/50 basis, and Atinum will pay Gastar USA on an annual basis an amount equal to

10% of lease bonuses and third party leasing costs up to \$20.0 million and 5% of such costs on activities above \$20.0 million.

4. Long-Term Debt

Second Amended and Restated Revolving Credit Facility

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On June 7, 2013, Gastar USA entered into the Second Amended and Restated Credit Agreement, dated as of June 7, 2013, among Gastar USA, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and Issuing Lender and the lenders named therein (the “Revolving Credit Facility”). The New Revolving Credit Facility provides an initial borrowing base of $50.0 million, with borrowings bearing interest, at Gastar USA's election, at the reference rate or the Eurodollar rate plus an applicable margin. The reference rate is the greater of (i) the rate of interest publicly announced by the administrative agent or (ii) the federal funds rate plus 50 basis points. The applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the reference rate and from 2.0% to 3.0% in the case of borrowings based on the Eurodollar rate, depending on the utilization percentage in relation to the borrowing base. An annual commitment fee of 0.5% is payable quarterly on the unutilized balance of the borrowing base. The New Revolving Credit Facility has a scheduled maturity of November 14, 2017.
The Revolving Credit Facility is guaranteed by 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 Revolving Credit 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 any 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 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 of Gastar USA, as defined in the Revolving Credit Facility.

On July 31, 2013, Gastar USA, together with the parties thereto, entered into the Waiver, Agreement and Amendment No. 1 to Second Amended and Restated Credit Agreement (the “First Amendment”). The First Amendment amended the Revolving Credit Facility to clarify the current ratio covenant calculation.

On October 18, 2013, Gastar USA, together with the parties thereto, entered into the Agreement and Amendment No. 2 (“Amendment No. 2”) to Second Amended and Restated Credit Agreement, dated as of June 7, 2013. Amendment No. 2 amended the Revolving Credit Facility to, among other things, (i) increase the aggregate principal amount of the Notes permitted to be issued from $200.0 million to $325.0 million, (ii) allow for the issuance by Gastar USA of Series B Preferred Stock and (iii) increase the aggregate amount of cash dividends permitted to be paid to preferred stockholders from $12.5 million to $20.0 million.
On December 9, 2013, the borrowing base under the Revolving Credit Facility was increased by the lending participants to $100.0 million.
Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. Gastar USA and its lenders may each request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. At December 31, 2013, the Revolving Credit Facility had a borrowing base of $100.0 million, with no borrowings outstanding and availability of $100.0 million. The next regularly scheduled redetermination is set for May 2014. Future increases in the borrowing base in excess of the original $50.0 million are limited to 17.5% of the increase in adjusted consolidated net tangible assets as defined in the Notes agreement (as discussed below in “Senior Secured Notes”).

On December 18, 2013, Parent entered into a parent guarantee agreement (the “Credit Facility Guaranty”) to guaranty Gastar USA’s obligations under the Revolving Credit Facility. Pursuant to the Credit Facility Guaranty, Parent irrevocably and unconditionally guaranteed the punctual payment and performance of all obligations under the Revolving Credit Facility, subject to fraudulent transfer laws, in the manner and to the extent set forth in the Credit Facility Guaranty.

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At December 31, 2013, Gastar USA was in compliance with all financial covenants under the Revolving Credit Facility.

Amended and Restated Revolving Credit Facility

For the period October 28, 2009 through June 6, 2013, Gastar USA, together with the other parties thereto, was subject to an amended and restated credit facility (the “Prior Revolving Credit Facility”). The Prior Revolving Credit Facility provided for various borrowing base amounts based on an initial borrowing base of $47.5 million and a final borrowing base of $160.0 million effective March 31, 2013. Borrowings bore interest, at Gastar USA’s election, at the prime rate or LIBO rate plus an applicable margin. The applicable interest rate margin varied 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% was payable quarterly based on the unutilized balance of the borrowing base. The Prior Revolving Credit Facility had a final scheduled maturity date of September 30, 2015.

The Prior Revolving Credit Facility was guaranteed by Parent (as defined in the Prior Revolving Credit Facility) and all of Gastar USA’s current domestic subsidiaries and all future domestic subsidiaries formed during the term of the Prior Revolving Credit Facility. Borrowings and related guarantees were 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 was 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 Prior Revolving Credit Facility contained various covenants, including among others:

- Restrictions on liens, incurrence of other indebtedness without lenders' consent and other restricted payments including a restriction on the amount of cash dividends to be paid in aggregate on the Gastar USA Series A Preferred Stock each calendar year, subject to certain available commitment thresholds;
- Limitation of hedging volumes with a final limitation of 100% of the proved developed reserves as reflected in Gastar USA's reserve report using hedging other than floors and protective spreads;
- 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, except for quarters ending on March 31, 2013 through December 31, 2013 whereby the ratio was reduced to 0.6 to 1.0 and making certain changes in the calculation of current liabilities for such periods to exclude advances from non-operators;
- 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 became 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 Prior Revolving Credit Facility) of the Parent.

The Prior Revolving Credit Facility was amended and restated on June 7, 2013.

Senior Secured Notes

On May 15, 2013, Gastar USA issued $200.0 million aggregate principal amount of its 8 5/8% Senior Secured Notes due May 15, 2018 under an indenture (the “Indenture”) by and among Gastar USA, the Guarantors named therein (the “Guarantors”), Wells Fargo Bank, National Association, as Trustee (in such capacity, the “Trustee”) and Collateral Agent (in such capacity, the “Collateral Agent”). On November 15, 2013, Gastar USA issued an additional $125.0 million aggregate principal amount of additional notes under the Indenture. The 8 5/8% Senior Secured Note due 2018 are collectively referred to as the “Notes.” The Notes bear interest at a rate of 8.625% per year, payable semiannually in arrears on May 15 and November 15 of each year, beginning on November 15, 2013. The Notes will mature on May 15, 2018. The Company received net proceeds of approximately $312.3 million, net of debt issuance costs and

any original issue discounts.
In the event of a change of control, as defined in the Indenture, each holder of the Notes will have the right to require Gastar USA to repurchase all or any part of their notes at an offer price in cash equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase.

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The Notes are fully and unconditionally guaranteed, jointly and severally, on a senior secured basis by each of Gastar USA's material subsidiaries and certain future domestic subsidiaries (the “Guarantees”). The Notes and Guarantees will rank senior in right of payment to all of Gastar USA's and the Guarantors' future subordinated indebtedness and equal in right of payment to all of Gastar USA's and the Guarantors' existing and future senior indebtedness. The Notes and Guarantees also will be effectively senior to Gastar USA's unsecured indebtedness and effectively subordinated to Gastar USA's and Guarantors' indebtedness under the Revolving Credit Facility, any other indebtedness secured by a first-priority lien on the same collateral and any other indebtedness secured by assets other than the collateral, in each case to the extent of the value of the assets securing such obligation.

The Indenture contains covenants that, among other things, limit Gastar USA's ability and the ability of its subsidiaries to:

- Transfer or sell assets or use asset sale proceeds;
- Pay dividends or make distributions, redeem subordinated debt or make other restricted payments;
- Make certain investments; incur or guarantee additional debt or issue preferred equity securities;
- Create or incur certain liens on Gastar USA's assets;
- Incur dividend or other payment restrictions affecting future restricted subsidiaries;
- Merge, consolidated or transfer all or substantially all of Gastar USA's assets;
- Enter into certain transactions with affiliates; and
- Enter into certain sale and leaseback transactions.

These and other covenants that are contained in the Indenture are subject to important limitations and qualifications that are described in the Indenture.

On May 15, 2013 and November 15, 2013, in connection with each issuance and sale of the Notes, Gastar USA and each of the Guarantors entered into Registration Rights Agreements (together, the “Registration Rights Agreements”) with Imperial Capital, LLC, as representative of the initial purchasers. Under the Registration Rights Agreement, Gastar USA agreed, subject to certain exceptions, to (i) file a registration statement with the SEC with respect to an exchange of the Notes for new notes having terms substantially identical in all material respects to the Notes (except that the exchange notes will not contain terms relating to transfer restrictions), (ii) use its reasonable best efforts to cause the exchange offer registration statement to be declared effective under the Securities Act of 1933, as amended, within 360 days after the issue date of the Notes, (iii) as soon as practicable after the effectiveness of the exchange offer registration statement, offer the exchange notes in exchange for the Notes, and (iv) keep the registered exchange offer open for not less than 30 days (or longer if required by applicable law) after the date of the registered exchange offer is mailed to the holders of the Notes. Gastar USA and the Guarantors also agreed to file a shelf registration statement for the resale of the Notes if an exchange offer cannot be effected within the time period specified above and in other circumstances.

On December 23, 2013, Parent entered into the Parent Guarantee Agreement (the “Notes Guarantee”). Pursuant to the Notes Guarantee, Parent jointly and severally, unconditionally guaranteed all notes issued under the indenture governing the Notes.

At December 31, 2013, the Notes reflected a balance of $313.0 million, net of unamortized discounts of $12.0 million, on the consolidated balance sheets.

5. 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,		
	2013	2012	2011
	(in thousands)		
Asset retirement obligation, beginning of year	$6,963	$8,275	$7,249
Liabilities incurred during period	3,416	271	492
Liabilities settled during period	(126)	(297)	—
Accretion expense	468	388	534
Revision in previous estimates and other	60	553	—
Deletions related to property disposals	(4,718)	$(2,227)	—
Asset retirement obligation, end of year	$6,063	$6,963	$8,275

As of December 31, 2013, the current portion of the Company's asset retirement obligation was $633,000 and was recorded in current liabilities on the consolidated balance sheet.

6. 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 years ended December 31, 2013 and 2012, management's evaluation of unproved properties resulted in an impairment. Due to continued low natural gas prices for dry gas and no current plans to drill or extend leases in Marcellus East or East Texas, the Company reclassified $20.5 million and $24.4 million of unproved properties to proved properties for the years ended December 31, 2013 and 2012, respectively. As no other fair value measurements are required to be recognized on a non-recurring basis at December 31, 2013, no additional disclosures are provided at December 31, 2013.

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

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settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its 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 2013 and 2012 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, 2013 and 2012:

	Fair value as of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$32,393	$—	$—	$32,393
Commodity derivative contracts	—	—	7,545	7,545
Liabilities:				
Commodity derivative contracts	—	—	(3,781)	(3,781)
Total	$32,393	$—	$3,764	$36,157

	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
Restricted cash	—	—	—	—
Commodity derivative contracts	—	—	9,168	9,168
Liabilities:				
Commodity derivative contracts	—	—	(2,703)	(2,703)
Total	$8,901	$—	$6,465	$15,366

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, 2013 and 2012. 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, 2013 and 2012.

	For the years ended December 31,	
	2013	2012
	(in thousands)	
Balance at beginning of period	$6,465	$15,873
Total gains (losses):		
included in earnings	(4,752)	7,236
Purchases	9,772	—
Issuances	(2,308)	—
Settlements (1)	(5,413)	(16,644)
Balance at end of period	$3,764	$6,465
The amount of total gains (losses) for the period included in earnings attributable to the change in the mark to market of commodity derivatives contracts still held at December 31, 2013 and 2012	$(9,967)	$(5,566)

(1) Included in (loss) gain on commodity derivatives contracts on the consolidated statement of operations.

At December 31, 2013, 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, 2013 was $324.6 million based on quoted market prices of the senior secured notes (Level 1). The estimated fair value of the Company's long-term debt at December 31, 2012 approximated the respective carrying value because the interest rate approximated 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 7, "Derivative Instruments and Hedging Activity."

7. 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 oil, condensate, natural gas and NGLs price risk.

All derivative contracts are carried at their fair value on the balance sheet and all changes in value are recorded in the consolidated statement of operations in (loss) gain on commodity derivatives contracts. For the year ended December 31, 2013, the Company reported a loss of $4.8 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, 2012 and 2011, the Company reported gains of $7.4 million and $12.2 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, 2013, 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	Ceiling (Short)
2014	Fixed price swap	11,136	4,064,500	$4.06	$—	$—	$—
2014	Fixed price swap	2,000	730,000	3.72	—	—	—
2014	Fixed price swap	2,000	730,000	3.98	—	—	—
2014	Fixed price swap	2,000	730,000	4.07	—	—	—
2014	Short calls	2,500	912,500	—	—	—	4.59
2014	Costless collar	3,000	1,095,000	—	4.00	—	4.36
2014	Costless collar	5,000	1,825,000	—	4.00	—	4.55
2014	Costless collar	2,500	912,500	—	4.00	—	4.71
2014 (1)	Short puts	10,500	966,000	—	—	3.00	—
2015	Fixed price swap	400	146,000	4.00	—	—	—
2015	Fixed price swap	2,500	912,500	4.06	—	—	—
2015	Protective spread	2,600	949,000	4.00	—	3.25	—
2015	Costless three-way collar	2,000	760,000	—	4.00	3.25	4.58
2016	Protective spread	2,000	732,000	4.11	—	3.25	—
2016	Costless three-way collar	2,000	732,000	—	4.00	3.25	4.58

(1) For the period October to December 2014.

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As of December 31, 2013, 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	Ceiling (Short)
2014 (2)	Fixed price swap	300	54,300	$98.05	$—	$—	$—
2014 (2)	Fixed price swap	550	99,550	95.15	—	—	—
2014 (2)	Fixed price swap	900	162,900	93.21		—	—
2014 (3)	Fixed price swap	750	138,000	90.35	—	—	—
2014 (3)	Fixed price swap	200	36,800	93.00	—	—	—
2014 (3)	Fixed price swap	350	64,400	91.55	—	—	—
2014	Fixed price swap	500	182,500	91.10	—	—	—
2014	Fixed price swap	270	98,500	90.77	—	—	—
2014	Costless collar	200	73,000	—	98.00	—	98.00
2014 (4)	Put spread	200	24,400	—	93.00	73.00	—
2015	Costless three-way collar	400	146,000	—	85.00	70.00	96.50
2015	Costless three-way collar	345	126,100	—	85.00	65.00	97.80
2015 (5)	Costless three-way collar	150	27,150	—	85.00	65.00	96.25
2015 (6)	Costless three-way collar	50	9,200	—	85.00	65.00	96.25
2015 (5)	Put spread	700	126,700	—	90.00	70.00	—
2015	Put spread	250	91,250	—	89.00	69.00	—
2015 (6)	Put spread	600	110,400	—	87.00	67.00	—
2016	Costless three-way collar	275	100,600	—	85.00	65.00	95.10
2016	Costless three-way collar	330	120,780	—	80.00	65.00	97.35
2016	Put spread	550	201,300	—	85.00	65.00	—
2016	Put spread	300	109,800	—	85.50	65.50	—
2017	Costless three-way collar	280	102,200	—	80.00	65.00	97.25
2017	Costless three-way collar	242	88,150	—	80.00	60.00	98.70
2017	Put spread	500	182,500	—	82.00	62.00	—
2018 (7)	Put spread	425	103,275	—	80.00	60.00	—

(1) Crude volumes hedged include oil, condensate and certain components of our NGLs production.
(2) For the period January to June 2014.
(3) For the period July to December 2014.
(4) For the period September to December 2014.
(5) For the period January to June 2015.
(6) For the period July to December 2015.
(7) For the period January to August 2018.

As of December 31, 2013, the Company did not have any NGLs derivative transactions outstanding.

As of December 31, 2013, 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. 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 December 2013 through August 2018. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company began amortizing the deferred put premium

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liabilities in December 2013. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

	For the Years Ended December 31,	
	2013	2012
	(in thousands)	
Current commodity derivative premium put payable	$145	$—
Long-term commodity derivative premium payable	7,000	—
Total unamortized put premium liabilities	$7,145	$—

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of December 31, 2013:

	Amortization
	(in thousands)
September to December 2014	$145
January to December 2015	2,298
January to December 2016	2,408
January to December 2017	1,460
January to August 2018	834
Total unamortized put premium liabilities	$7,145

Additional Disclosures about Derivative Instruments and Hedging Activities

The tables below provide information on the location and amounts of commodity derivative fair values in the consolidated statement of financial position and commodity 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)		
		Fair Value December 31,	
	Balance Sheet Location	2013	2012
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$—	$7,799
Commodity derivative contracts	Other assets	7,545	1,369
Commodity derivative contracts	Current liabilities	(3,403)	(1,399)
Commodity derivative contracts	Long-term liabilities	(378)	(1,304)
Total derivatives not designated as hedging instruments		$3,764	$6,465

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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, 2013	2012	2011
		(in thousands)		
Derivatives not designated as hedging instruments				
Commodity derivative contracts	(Loss) gain on commodity derivatives contracts	$(4,752)	$7,422	$12,204
Commodity derivative contracts	Interest expense	—	(186)	(136)
Total		$(4,752)	$7,236	$12,068

8. Capital Stock

Common Stock

On November 14, 2013, Parent changed its jurisdiction of incorporation to the State of Delaware and entered into new articles of incorporation pursuant to which 275,000,000 shares of Parent's common stock, $0.001 par value per share, are authorized for issuance. Prior to November 14, 2013, Parent’s articles of incorporation allowed Parent to issue an unlimited number of common shares without par value.

On January 31, 2014, Parent entered into an Agreement and Plan of Merger (the “Merger Agreement”) pursuant to which Parent merged with and into Gastar USA, a direct subsidiary of Parent, as part of a reorganization to eliminate Parent's holding company corporate structure. Pursuant to the Merger Agreement, shares of Parent's common stock were converted into the right to receive an equal number of shares of common stock of Gastar USA, which together with its subsidiaries, owns and continues to conduct business in substantially the same manner as it was being conducted by Parent and its subsidiaries immediately prior to the merger.

Parent Preferred Shares

Under Parent's Delaware articles of incorporation, 40,000,000 shares of preferred stock, $0.01 par value per share, are authorized for issuance. At December 31, 2013, Parent had no preferred shares issued or outstanding.

Other Share Issuances

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

	For the Years Ended December 31, 2013	2012
Other stock issuances:		
Shares of restricted common stock granted	2,288,179	1,916,981
Shares of restricted common stock vested	762,682	505,203
Stock options exercised	10,000	3,000
Shares of restricted common stock surrendered upon vesting/exercise (1)	224,500	141,458
Shares of restricted common stock forfeited	512,862	74,463

(1) Represents shares of common stock forfeited in connection with the payment of estimated withholding taxes on shares of restricted common stock 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 stockholders 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 1,544,838 shares available for issuance under the Parent's 2006 Long-Term Stock Incentive Plan at December 31, 2013.

Shares Reserved
At December 31, 2013, Parent had 874,100 shares of common stock reserved for the exercise of stock options and 1,420,981 shares reserved for the settlement of PBUs.
Shares Owned by Chesapeake Energy Corporation
On March 28, 2013, the Company entered into a Settlement Agreement, dated March 28, 2013, between Chesapeake Exploration, L.L.C. and Chesapeake Energy Corporation (collectively, “Chesapeake”) and the Company, Gastar Texas and Gastar Texas, LLC (the “Settlement Agreement”). Pursuant to the Settlement Agreement, the Company settled and resolved all claims of Chesapeake and its subsidiaries against the Company and its subsidiaries made in a previously disclosed lawsuit filed in the U.S. District Court for the Southern District of Texas. In order to effect a mutual full and unconditional release and settlement of all claims made in the lawsuit filed by Chesapeake, the Company paid Chesapeake approximately $10.8 million in cash, approximately $9.8 million of which was paid for the repurchase of 6,781,768 outstanding shares of common stock of Parent held by Chesapeake Energy Corporation upon the closing of the stock repurchase and settlement on June 7, 2013. See Note 14, “Commitments and Contingencies.”
Gastar USA Common Stock
At December 31, 2013 and 2012, all 750 shares of Gastar USA's common stock 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 Delaware certificate of incorporation allowed 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.
On October 25, 2013, Gastar USA filed an Amended and Restated Certificate of Incorporation (the “A&R Certificate”) with the Secretary of State of the State of Delaware. Under the A&R Certificate, the capital stock authorized for issuance was increased from 1,000 shares of common stock, without par value, to 275,000,000 shares of common stock, par value $0.001 per share.
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 Delaware certificate of incorporation allowed Gastar USA to issue 10,000,000 shares of preferred stock, $0.01 par value per share. The preferred stock was permitted to be issued from time to time in one or more series. Gastar USA’s Board of Directors (the “Gastar USA Board”) was 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 was 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). Pursuant to the A&R Certificate, the number of shares of preferred stock authorized for issuance was increased to 40,000,000 shares.
Series A Preferred Stock
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 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, 2013, Gastar USA sold 6,906 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $136,000, resulting in 3,958,160 total shares of Series A Preferred Stock issued for total net proceeds, inception to date, of $76.8 million at December 31, 2013. From January 1, 2014 to March 11, 2014, Gastar USA sold 26,203 additional shares of Series A Preferred Stock for net proceeds of $628,000.

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

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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
Prior to June 23, 2014	$25.25
On or after June 23, 2014	$25.00

There is no mandatory redemption of the Series A Preferred Stock.

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, 2013, 2012 and 2011, Gastar USA paid dividends of $8.5 million, $7.1 million and $1.0 million, respectively.

Series B Preferred Stock

On October 29, 2013, Gastar USA sold 2,000,000 shares of its 10.75% Series B Cumulative Preferred Stock, par value $0.01 per share and liquidation preference $25.00 per share (the "Series B Preferred Stock"), in an underwritten public offering. On November 1, 2013, the underwriters partially exercised their option to purchase additional shares of Series B Preferred Stock and purchased an additional 140,000 shares of Series B Preferred Stock. The issuance of the 2,140,000 shares of Series B Preferred Stock closed on November 7, 2013 with Gastar USA receiving net proceeds of approximately $50.1 million after deducting underwriting commissions and offering expenses.

The Series B Preferred Stock rank senior to Gastar USA's common stock and on parity with its 8.625% Series A Cumulative Preferred Stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding up. The Series B Preferred Stock are subordinated to all of Gastar USA's existing and future debt and all future capital stock designated as senior to the Series B Preferred Stock. The 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 B Preferred Stock, to the extent described in the guarantee agreement. Parent's obligations with respect to the guarantee are effectively subordinated to all of its existing and future debt.

Except upon a change in ownership or control, the Series B Preferred Stock may not be redeemed before November 15, 2018, at or after which time it may be redeemed at Gastar USA's option for $25.00 per share in cash. Following a change in ownership or control, Gastar USA will have the option to redeem the Series B Preferred Stock, in whole but not in part for $25.00 per share in cash, plus accrued and unpaid dividends (whether or not declared), up to, but not including the redemption date. If Gastar USA does not exercise its option to redeem the Series B Preferred Stock upon a change of ownership or control, the holders of the Series B Preferred Stock have the option to convert the shares of Series B Preferred Stock into up to and aggregate of 11.5207 shares of Gastar USA's common stock per share of Series B Preferred Stock, subject to certain adjustments. If Gastar USA exercises any of its redemption rights relating to shares of Series B Preferred Stock, the holders of Series B Preferred Stock will not have the conversion right described above with respect to the shares of Series B Preferred Stock called for redemption. Notwithstanding any of the foregoing, if a change of ownership or control occurs prior to the consummation of the Reorganization Transactions (as defined in the Certificate of Designation), (i) the holders of Series B Preferred Stock shall not have the conversion right described above and (ii) the dividend rate shall increase to 12.75%.

There is no mandatory redemption of the Series B Preferred Stock.

Gastar USA will pay cumulative dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference. For the year ended December 31, 2013, Gastar USA paid dividends of $847,000.

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9. Equity Compensation Plans
Share-Based Compensation Plan
At the annual meeting of stockholders held June 4, 2009, Parent's stockholders 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 shares of common stock previously reserved and available for issuance under the 2002 Stock Option Plan, including any shares of common stock subject to outstanding stock option awards previously granted under the 2002 Stock Option Plan prior to the effective date of the amendments, to the shares of common stock 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 shares of common stock withheld from or netted against the total number of shares of common stock 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 shares of common stock 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 shares of common stock 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 shares of common stock 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 shares of common stock (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 stockholders held June 7, 2012, Parent's stockholders approved the Second Amendment to the 2006 Plan that, effective June 3, 2012, increased the total number of shares of common stock 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 shares of common stock. 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 shares of common stock 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, 2013, 1,544,838 shares of common stock of Parent were available for future stock-based compensation grants under the 2006 Plan. All shares of common stock issued upon the exercise of stock option grants or vesting of restricted stock grants are authorized, issued by Parent and are fully paid and non-assessable.
In connection with the merger, the 2006 Plan was assumed by Gastar Exporation Inc. and, effective as of the merger, was amended, restated and renamed the “Gastar Exploration Inc. Long-Term Incentive Plan” (as amended, the “LTIP”). The LTIP provides for substantially the same terms as the 2006 Plan, except the LTIP provides for awards with respect to Gastar Exploration Inc. common stock rather than Parent common stock. All unexercised and unexpired options to purchase Parent’s common stock, restricted shares of Parent and other rights to acquire Parent common

stock under the 2006 Plan (including performance-based units) became options to purchase, restricted stock or other rights to acquire the same number of shares of Gastar Exploration Inc. pursuant to the LTIP, subject to the same terms and conditions, including the per share exercise price (but, in the case of performance awards, performance from and after the effective time of the merger will be determined with respect to the stock price of Gastar Exploration Inc. rather than Parent).

Determining Fair Value of Stock Options

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

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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 2013, 2012 and 2011, the Company used forfeiture rates in determining compensation expense of 14%, 15.5% and 8.5%, respectively.
The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes-Merton valuation pricing model. There were no stock options granted during the years ended December 31, 2013, 2012 and 2011.
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,		
	2013	2012	2011
	(in thousands, except per share data)		
Weighted average grant date fair value per stock option granted	$—	$—	$—
Intrinsic value of stock options exercised (1)	$19	$2	$18
Grant date fair value of stock options vested	$88	$117	$282

(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, 2013:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2012	959,100	$ 11.31		
Granted	—	—		
Exercised	(10,000)	2.60		
Canceled/Expired	—	—		
Forfeited	(75,000)	8.18		
Outstanding at December 31, 2013	874,100	$ 11.68		
Options vested and exercisable at December 31, 2013	864,100	$ 11.76	3.17	$739

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	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, 2012	80,725	$ 2.07			
Granted	—	—			
Vested	(50,725)	1.73			
Forfeited	(20,000)	2.58			
Outstanding non-vested options at December 31, 2013	10,000	$ 2.74	$ 4.27	0.04	$27

There was no unrecognized expense as of December 31, 2013 for all outstanding options.

Restricted Share Activity

The following table summarizes information related to restricted shares at December 31, 2013:

	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, 2012	2,760,446	$2.75		
Granted	2,288,179	1.30		
Vested	(762,682)	3.57		
Forfeited	(512,862)	1.87		
Outstanding non-vested restricted shares at December 31, 2013	3,773,081	$1.82	8.68	$26,110

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:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands, except per share data)		
Weighted average grant date fair value per restricted share	$1.30	$2.09	$4.15
Total fair value of restricted shares vested	$2,725	$2,492	$2,436

Unrecognized compensation expense as of December 31, 2013 for all outstanding restricted share awards is $2.0 million and will be recognized over a weighted average period of 1.36 years.

Performance Based Units Activity

Pursuant to the 2006 Plan, as amended, the Company's Compensation Committee agreed to allocate a portion of the 2013 long-term incentive grants to executives as performance based units (“PBUs”). The PBUs represent a contractual right to receive shares of Parent's common stock, an amount of cash equal to the fair market value of a share of Parent's common stock, or a combination of shares of Parent's common stock and cash as of the date of settlement based on the number of PBUs to be settled. The settlement of PBUs may range from 0% to 200% of the targeted number of PBUs stated in the agreement contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PBUs vest equally and settlement is determined annually over a three year period. Any PBUs not vested at each measurement date will expire.

Compensation expense associated with PBUs is based on the grant date fair value of a single PBU as determined using a Monte Carlo simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the PBUs with shares of Parent's common stock at each measurement date, the PBU awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the PBU award.

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The table below provides a summary of PBUs as of the date indicated:

	PBUs	Fair Value per Unit
Unvested PBUs at December 31, 2012	—	$—
Granted	1,192,889	1.56
Vested	—	—
Forfeited	(127,155)	—
Unvested PBUs at December 31, 2013	1,065,734	$1.56

For the year ended December 31, 2013, the Company recognized $931,000 of compensation expense associated with the PBUs granted on January 30, 2013. As of December 31, 2013, the Company had $731,000 of total unrecognized expense for the PBUs.

Stock-Based Compensation Expense

For the years ended December 31, 2013, 2012 and 2011, the Company recorded stock-based compensation expense for restricted shares, PBUs, and stock options granted using the fair-value method of $3.4 million, $3.3 million and $2.6 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, 2013, the Company had approximately $2.7 million of total unrecognized compensation cost related to unvested stock options, restricted shares and PBUs, which is expected to be amortized over the following periods:

	Amount (in thousands)
2014	$2,028
2015	594
2016	66
Total	$2,688

10. Interest Expense

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

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Interest expense:			
Cash and accrued	$14,130	$1,992	$682
Amortization of deferred financing costs (1)(2)	2,322	224	249
Capitalized interest	(3,284)	(1,946)	(818)
Total interest expense	$13,168	$270	$113

(1) The year ended December 31, 2013 includes $1.2 million of deferred financing costs written off as a result of the Revolving Credit Facility. See Note 4, “Long-Term Debt - Second Amended and Restated Revolving Credit Facility.”

(2) The year ended December 31, 2013 includes $716,000 of debt discount accretion related to the Notes.

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

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Interest expense:			
Cash and accrued	$13,978	$1,993	$681
Amortization of deferred financing costs and debt discount (1)(2)	2,322	224	248
Capitalized interest	(3,284)	(1,946)	(817)
Total interest expense	$13,016	$271	$112

(1) The year ended December 31, 2013 includes $1.2 million of deferred financing costs written off as a result of the Revolving Credit Facility. See Note 4, "Long-Term Debt - Second Amended and Restated Revolving Credit Facility."

(2) The year ended December 31, 2013 includes $716,000 of debt discount accretion related to the Notes.

11. Related Party Transactions

Chesapeake Energy Corporation

Chesapeake Energy Corporation acquired 6,781,768 of Parent's common shares during 2005 to 2007 in a series of private placement transactions. On March 28, 2013, the Company entered into a Settlement Agreement between Chesapeake and the Company, Gastar Texas and Gastar Texas LLC (the "Settlement Agreement"). Pursuant to the Settlement Agreement, the Company settled and resolved all claims of Chesapeake and its subsidiaries against the Company and its subsidiaries made in a previously disclosed lawsuit filed in the U.S. District Court for the Southern District of Texas. In order to effect a mutual full and unconditional release and settlement of all claims made in the lawsuit filed by Chesapeake, the Company paid Chesapeake approximately $10.8 million in cash, approximately $9.8 million of which was paid for the repurchase of 6,781,768 outstanding common shares of Parent held by Chesapeake upon the closing of the stock repurchase and settlement on June 7, 2013. See Note 8, "Capital Stock - Shares Owned by Chesapeake Energy Corporation."

Also on March 28, 2013, the Company entered into the Chesapeake Purchase Agreement, pursuant to which Gastar USA acquired the Chesapeake Assets on June 7, 2013. See Note 3, "Property, Plant and Equipment - Chesapeake Acquisition."

As of December 31, 2013, Chesapeake Energy Corporation did not own any of Parent's outstanding common shares.

12. 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,		
	2013	2012	2011
	(in thousands)		
United States	$51,276	$(152,322)	$285
Foreign	(1,934)	(1,469)	(1,025)
Total income (loss) before income taxes	$49,342	$(153,791)	$(740)

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

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Current:			
Federal	$—	$—	$—
State	—	—	—
Foreign	—	—	—
Provision for income taxes	$—	$—	$—

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Deferred:			
Federal	$(15,299)	$—	$—
State	(743)	—	—
Foreign	—	—	—
Income tax expense (benefit)	$(16,042)	$—	$—

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,		
	2013	2012	2011
	(in thousands)		
Expected income tax provision (benefit) at statutory rate	$11,655	$(53,827)	$(259)
State tax, tax effected	96	(2,562)	—
Non-deductible stock-based compensation expense	605	560	441
Tax effect of Canadian tax rate differences	193	(125)	(103)
Loss of Canadian tax attributes due to migration from Canada	19,825	—	—
Gain on acquisition of assets at fair value	(9,685)	—	—
Non-deductible costs of migration from Canada to U.S.	95	—	—
Other	(49)	15	10
Other changes in valuation allowance	(38,777)	55,939	(89)
Actual income tax provision	$(16,042)	$—	$—

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

	As of December 31,	
	2013	2012
	(in thousands)	
Deferred tax asset (liability):		
Capital assets	$(70,955)	$(22,668)
Net operating loss carry forwards	122,675	93,339
Foreign tax credit carry forwards	50,681	50,681
Valuation allowance	(102,401)	(121,352)
Net deferred tax asset	$—	$—

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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 has approximately $333.9 million of net operating loss carry forwards as of December 31, 2013, 2012which, if not utilized, will expire beginning in 2030. For U.S. federal income tax purposes, as of December 31, 2013, 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.
Effective November 14, 2013, the Company withdrew from Canada and re-incorporated in Delaware (the "Migration"). As a result of the Migration, the Company's Canadian tax attributes have effectively been forfeited. As all of the Canadian tax attributes were subject to a valuation allowance, the Migration from Canada to the U.S. is not expected to result in any Canadian tax expense. The following tables present the Canadian tax attributes forfeited and the release of the Canadian valuation allowance resulting from the Migration.

	As of December 31,	
	2013	2012
	(in thousands)	
Canadian and foreign exploration and development expense	$—	$2,597
Undeducted share issuance costs	$—	$1,239
Undeducted non-capital and capital loss carry forwards	$—	$73,522

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

	As of December 31,	
	2013	2012
	(in thousands)	
Deferred tax asset:		
Capital assets	$—	$649
Share issuance costs	—	310
Tax loss carry forwards	—	18,381
Valuation allowance	—	(19,340)
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, 2013, 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.
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.

13. 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.

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	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands, except per share and share data)		
Net loss attributable to Gastar Exploration, Inc.	$39,964	$(160,868)	$(1,764)
Weighted average shares of common stock outstanding - basic	60,220,115	63,538,362	63,003,579
Incremental shares from unvested restricted shares	2,869,490	—	—
Incremental shares from outstanding stock options	26,095	—	—
Incremental shares from outstanding PBUs	502,701	—	—
Weighted average shares of common stock outstanding - diluted	63,618,401	63,538,362	63,003,579
Net loss per share of common stock attributable to Gastar Exploration, Inc. Common Stockholders:			
Basic	$0.66	$(2.53)	$(0.03)
Diluted	$0.63	$(2.53)	$(0.03)
Shares of common stock excluded from denominator as anti-dilutive:			
Unvested restricted shares	3,505	1,831,435	641,606
Stock options	—	936,967	810,235
Total	3,505	2,768,402	1,451,841

14. 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, 2013, 2012 and 2011, office lease expense totaled approximately $372,000, $377,000 and $160,000, respectively.

As of December 31, 2013, the Company's aggregate future minimum annual rental commitments under the non-cancelable leases for the next five years are as follows:

2014	$681
2015	602
2016	453
2017	142
2018	117
	$1,995

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-asserted 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 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 ("Navasota") litigation, 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 the new lawsuit, Chesapeake re-asserted 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 alleged 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 established that there was a mutual mistake of fact and a failure of consideration with regard to the November 2005 Agreements. In the alternative, Chesapeake claimed that the Gastar defendants had 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 offered to return Parent's common shares purchased pursuant to the Common Stock Purchase Agreement, and sought restitution from the Gastar defendants of the net amount of approximately $101.4 million, which included 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 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 responded to the lawsuit by filing a motion to dismiss, contending that the claims failed as a matter of law. Specifically, the Gastar defendants contended in the motion to dismiss 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 contended in the motion to dismiss 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 contended in the motion to dismiss that it is barred by the two-year statute of limitations and that in any event, it failed 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 contended in their response to the motion to compel arbitration 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.

On March 28, 2013, the Company entered into a Settlement Agreement between Chesapeake and the Gastar defendants (the "Settlement Agreement"). Pursuant to the Settlement Agreement, the Gastar defendants settled and resolved all claims of Chesapeake and its subsidiaries against the Company and its subsidiaries made in the Chesapeake lawsuit. In order to affect a mutual full and unconditional release and settlement of all claims made in the lawsuit filed by Chesapeake, the Company paid Chesapeake approximately $10.8 million in cash, approximately $9.8 million of which was paid for the repurchase of 6,781,768 outstanding common shares of the Company currently held by Chesapeake Energy Corporation.

On the same day that the Company entered into the Settlement Agreement, Gastar USA entered into an agreement for the acquisition of certain properties from Chesapeake. The closing of the proposed property acquisition, stock repurchase and settlement for an adjusted aggregate cash payment of $80.0 million, comprised of approximately $69.4 million in property acquisition costs (subject to adjustment for an acquisition effective date of October 1, 2012), stock repurchase price of approximately $9.8 million and an additional $1.0 million for litigation settlement occurred on

June 7, 2013. On March 31, 2013, following notification to the Court regarding the execution of the settlement agreement, the Court in the Chesapeake lawsuit entered an order of dismissal, without prejudice to the right of counsel of record to move for reinstatement of the case within 90 days in the event the settlement is not consummated.

The acquisition transaction closed on June 7, 2013, and the payments described above were made as provided in the Settlement Agreement and the agreement for acquisition of properties from Chesapeake. Thereafter, the parties to the Chesapeake lawsuit filed a stipulation of dismissal of prejudice, and on June 11, 2013, the court entered an order dismissing the case with prejudice.

Gastar Exploration USA, Inc., et al v. Williams Ohio Valley Midstream LLC (American Arbitration Association Matter No. 70-198-Y-00461-13). On July 16, 2013, Gastar USA and two similarly situated co-claimants initiated an arbitration proceeding against Williams Ohio Valley Midstream LLC ("Williams OVM"). The claimants allege that Williams OVM has breached various agreements relating to the gathering, processing and marketing of natural gas, NGLs and condensate

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produced from properties that are owned in part by Gastar USA in the Marcellus Shale in Marshall and Wetzel Counties, West Virginia, and request that an Arbitration Panel assess an unspecified amount of damages against Williams OVM for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs as provided in the agreements. On August 7, 2013, Williams OVM filed an answering statement and counterclaim for damages in excess of $612,000 in the arbitration matter. On December 31, 2013, the parties informed the Arbitration Panel that they have reached an agreement in principle to settle their disputes. The settlement is subject to final documentation, which has not yet been completed. At the request of both parties, on January 9, 2014, the Arbitration Panel stayed all proceedings, pending completion of the final settlement documentation.

Gastar Exploration Ltd vs U.S. Specialty Ins. Co. and Axis Ins. Co. (Cause No. 2010-11236) District Court of Harris County, Texas 190th Judicial District. On February 19, 2010, the Company filed a lawsuit claiming that the Company was due reimbursement of qualifying claims related to the settlement and associated legal defense costs under the Company's directors and officers liability insurance policies related to the ClassicStar Mare Lease Litigation settled on December 17, 2010 for $21.2 million. The combined coverage limits under the directors and officers liability coverage are $20.0 million. The District Court granted the underwriters' summary judgment request by a ruling dated January 4, 2012. The Company appealed the District Court ruling and on July 15, 2013, the Fourteenth Court of Appeals of Texas reversed the summary judgment ruling granted against the Company on the basis of the policies' prior-and-pending litigation endorsement and remanded the case for further proceedings in the District Court. The insurers filed a motion for reconsideration in the Court of Appeals, which that court denied. The insurers are seeking discretionary review from the Texas Supreme Court, and their petition for review was filed on February 18, 2014. The petition becomes ripe for review thirty days after that. If none of the justices votes for any action, then the petition is denied automatically thirty-one days after the justices received it (61 days from filing date). If the Texas Supreme Court denies review or affirms the Fourteenth Court of Appeals' ruling, the case will be remanded to the District Court. The District Court proceedings will include, but not be limited to, a determination of whether the Company's claims are securities claims covered by the insuring agreements.

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 had a term of 10 years. Prior to the sale of the Company's interest in the East Texas properties, ETC provided Gastar USA 50.0 MMcf per day of treating capacity and 150.0 MMcf/d of transportation capacity of production from Gastar USA's wells, located in Leon and Robertson Counties, Texas. Upon the sale of the Company's interest in the East Texas properties on October 2, 2013, the purchaser of the East Texas properties assumed the contractual obligations under the ETC Contract.

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. Prior to the Company's sale of its interest in the East Texas properties, the Hilltop Gathering Agreement covered 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. Gastar USA was also obligated to connect new wells that it drilled within the area covered by the Hilltop Gathering Agreement to the Hilltop Gathering System. The Hilltop Gathering Agreement provided for a minimum quarterly gathering gross production volume of 50.0 MMcf/d (35.0 MMcf/d 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 was less than the minimum quarterly requirement, the gathering fee was payable on such deficit. If excess quarterly production existed, such excess was carried forward to be used to offset any future deficit quarters. The gathering fee on the initial gross 25.0 Bcf of production was $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reached 300.0 Bcf. For the year ended December 31, 2013, Gastar USA paid $1.8 million to Hilltop Resort as a result of actual production volumes being less than minimum contractual volume requirements. Upon the sale of the Company's interest in the East Texas properties on October 2, 2013, the purchaser of the East Texas properties assumed any future minimum volume requirement obligations under the Hilltop Gathering Agreement.

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

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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 520.0 MMcf/d 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, 2013, the Company had total liabilities of $6.1 million related to asset retirement obligations of which $633,000 is recorded as short-term liabilities and $5.4 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 5, "Asset Retirement Obligation."

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.

15. Concentration of Risk and Significant Customers

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

	For the Years Ended December 31,		
	2013	2012	2011
Marcellus Shale and Other Appalachia	65 %	72 %	15 %
Mid-Continent	26 %	— %	— %
Hilltop Area, East Texas (1)	9 %	27 %	79 %
Powder River Basin (2)	— %	1 %	6 %

(1) The Company's working interest in the Hilltop Area, East Texas was sold on October 2, 2013, with an effective date of January 1, 2013.

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

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

	For the Years Ended December 31,		
	2013	2012	2011
SEI	56 %	47 %	8 %
Sunoco	16 %	— %	— %
Clearfield Appalachian	8 %	14 %	— %
ETC	8 %	24 %	69 %
Plains Marketing LP	1 %	2 %	10 %

SEI and Clearfield Appalachian purchase the majority of the Company's Marcellus Shale and Other Appalachia production. There are limited oil, condensate, natural gas and NGLs purchase and transportation alternatives currently available in Appalachia. If SEI or Clearfield Appalachian were to cease purchasing and transporting the Company’s Marcellus Shale and Other Appalachia oil, condensate, natural gas 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. SEI and Sunoco purchase the majority of the Company's Mid-Continent production. There are numerous purchase and transportation alternatives currently available in the Mid-Continent so in the event that SEI or Sunoco were to cease purchasing and transporting our oil, condensate, natural gas and NGLS production, the Company's ability to conduct normal operations would not be significantly restricted. Prior to the Company's sale of its interest in East Texas, ETC treated, transported and purchased substantially all of the Company’s East Texas natural gas production and Plains Marketing LP purchased substantially all of the Company's East Texas oil production.

16. 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,		
	2013	2012	2011
	(in thousands)		
Cash paid for interest, net of capitalized amounts	$7,341	$39	$—
Non-cash transactions:			
Capital expenditures excluded from accounts payable and accrued drilling costs	$582	$4,666	$4,600
Capital expenditures excluded from accounts receivable	(4,077)	(929)	—
Capital expenditures excluded from prepaid expenses	—	—	48
Asset retirement obligation included in natural gas and oil properties	(1,302)	1,164	492
Asset retirement obligation sold/assigned to operator	(4,354)	(2,227)	—
Application of advances to operators	19,755	7,441	6,529
Other	47	(36)	—

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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,		
	2013	2012	2011
	(in thousands)		
Cash paid for interest, net of capitalized amounts	$7,341	$39	$—
Non-cash transactions:			
Capital expenditures excluded from accounts payable and accrued costs	$582	$4,666	$4,600
Capital expenditures excluded from accounts receivable	(4,077)	(929)	—
Capital expenditures excluded from prepaid expenses	—	—	48
Asset retirement obligation included in natural gas and oil properties	(1,302)	1,164	492
Asset retirement obligation assigned to operator	(4,354)	(2,227)	—
Application of advances to operators	19,755	7,441	6,529
Due to (from) Parent - transfer to equity, net	15,495	5,295	2,612
Other	47	(36)	—

17. Quarterly Consolidated Financial Data – Unaudited

The following tables summarize the Company's results of operations by quarter for the years ended December 31, 2013 and 2012:

	2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$11,264	$30,926	$18,840	$26,725
Income (loss) from operations	(1,849)	13,809	1,626	5,178
Income (loss) before provision for income taxes (1)	(2,456)	53,970	(1,808)	(16,406)
Net income (loss)	(2,456)	53,970	(1,808)	(364)
Dividend on preferred stock attributable to non-controlling interest	2,130	2,134	2,134	2,980
Net income (loss) attributable to Gastar Exploration, Inc.	(4,586)	51,836	(3,942)	(3,344)
Net income (loss) per share of common stock attributable to Gastar Exploration, Inc. Common Stockholders:				
Basic	$(0.07)	$0.83	$(0.07)	$(0.06)
Diluted	$(0.07)	$0.81	$(0.07)	$(0.06)
Weighted average shares of common stock outstanding:				
Basic	63,864,527	62,398,472	57,359,357	57,433,550
Diluted	63,864,527	63,813,423	57,359,357	57,433,550

(1) Income before provision for income taxes for the second quarter 2013 includes a gain on acquisition of assets at fair value of $43.7 million. Income before provision for income taxes for the fourth quarter 2013 includes adjustment to gain on acquisition of assets to reflect the deferred tax liabilities assumed of $16.0 million.

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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, Inc	(6,310)	(74,035)	(83,457)	2,934
Net income (loss) per share of common stock attributable to Gastar Exploration, Inc. Common Stockholders:				
Basic	$(0.10)	$(1.17)	$(1.31)	$0.05
Diluted	$(0.10)	$(1.17)	$(1.31)	$0.05
Weighted average shares of common stock 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 second and third quarters of 2012 include a quarterly ceiling test impairment charge of $72.7 million and $78.1 million, respectively.

The following tables summarize Gastar USA's results of operations by quarter for the years ended December 31, 2013 and 2012:

	2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$11,264	$30,926	$18,840	$26,725
Income (loss) from operations (1)	(1,628)	14,157	2,086	5,957
Income (loss) before provision for income taxes	(2,231)	54,312	(1,363)	(15,483)
Net income (loss)	(2,231)	54,312	(1,363)	559
Dividends on preferred stock	2,130	2,134	2,134	2,980
Net income (loss) attributable to common stockholder	(4,361)	52,178	(3,497)	(2,421)

(1) Income before provision for income taxes for the second quarter of 2013 includes a gain on acquisition of assets at fair value of $43.7 million. Income before provision for income taxes for the fourth quarter 2013 includes adjustment to gain on acquisition of assets to reflect the deferred tax liabilities assumed of $16.0 million.

	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 second and third quarters of 2012 include a quarterly ceiling test impairment charge of $72.7 million and $78.1 million, respectively.

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18. 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 oil and natural gas producing activities for the periods indicated:

	As of December 31,		
	2013	2012	2011
	(in thousands)		
Proved properties:			
United States	$935,773	$671,193	$514,357
Total proved properties	935,773	671,193	514,357
Unproved properties:			
United States	96,220	67,892	78,302
Total unproved properties	96,220	67,892	78,302
Total natural gas and oil properties	1,031,993	739,085	592,659
Less:			
Impairment of proved natural gas and oil properties			
United States	(337,939)	(337,939)	(187,152)
Accumulated depreciation, depletion and amortization	(177,790)	(145,631)	(120,436)
Net capitalized costs	$516,264	$255,515	$285,071

Pursuant to authoritative guidance for accounting for asset retirement obligations, net capitalized costs include related asset retirement costs of approximately $3.4 million, $4.8 million and $5.8 million at December 31, 2013, 2012 and 2011, respectively.

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

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

	For the years ended December 31,		
	2013	2012	2011
	(in thousands)		
Property acquisition			
Proved (1)	$189,594	$—	$—
Unproved (2)	71,472	25,676	19,552
Exploration	36,893	10,041	47,668
Development	53,058	111,878	18,167
Total costs incurred	$351,017	$147,595	$85,387

(1) The 2013 property acquisition costs excludes a downward adjustment of $2.6 million for fair value of acquisition.
(2) The 2013 property acquisition costs excludes $46.3 million of adjustment for fair value of acquisition.

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Results of Operations for Oil and Natural Gas Producing Activities

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

	For the Year Ended December 31,		
	2013	2012	2011
	(in thousands, except per Mcfe data)		
Oil, condensate, natural gas and NGLs sales, including commodity derivatives	$87,755	$49,940	$40,235
Production expenses	(18,113)	(13,408)	(13,751)
Impairment of oil and natural gas properties	—	(150,787)	—
Depreciation, depletion and amortization	(32,158)	(25,195)	(14,989)
Results of producing activities	$37,484	$(139,450)	$11,495
Depreciation, depletion and amortization per Mcfe	$1.66	$1.90	$1.95
Depreciation, depletion and amortization per MBoe	$9.94	$11.41	$11.70

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, before lease adjustments, that are the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil as of December 31, 2013 and 2012. The following table provides the key benchmark natural gas and oil prices used as of the periods indicated to calculate reserves:

	As of December 31,	
	2013	2012
Natural gas (per MMBtu):		
Henry Hub	$3.67	$2.76
Oil (per Bbl):		
WTI posting	$—	$91.21
WTI spot	$96.78	94.71

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, 2013, 2012, and 2011 and includes reserve information for the Marcellus Shale as of December 31, 2013, 2012, and 2011, reserve information for the Mid-Continent as of December 31, 2013 and reserve information for the Hilltop Area of East Texas as of December 31, 2012 and 2011. The Company sold its working interest in the Hilltop Area of East Texas on October 2, 2013,with an effective date of January 1, 2013. Proved oil and natural 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 natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped oil and natural 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.

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The following tables set forth changes in estimated net proved and proved developed and undeveloped reserves for the years ended December 31, 2013, 2012 and 2011:

Change in Proved Reserves	Natural Gas (MMcf) (1)	NGLs (MBbl) (2)	Condensate and Oil (MBbl) (2)	MMcfe (1) Equivalents (3)	MBoe (4) Equivalents (5)
Proved reserves as of December 31, 2010	49,892	—	61	50,260	8,376
2011 Activity:					
Extensions and discoveries	56,364	2,767	1,945	84,634	14,106
Revisions of previous estimates (6)	(7,286)	11	(45)	(7,494)	(1,248)
Production	(7,318)	(21)	(40)	(7,684)	(1,281)
Proved reserves as of December 31, 2011	91,652	2,757	1,921	119,716	19,953
2012 Activity:					
Extensions and discoveries (7)	57,835	2,783	2,439	89,169	14,861
Revisions of previous estimates	(6,518)	(348)	(796)	(13,375)	(2,230)
Production	(10,564)	(270)	(177)	(13,247)	(2,208)
Purchases in place	—	—	7	41	7
Sales in place	(1,395)	—	—	(1,395)	(231)
Proved reserves as of December 31, 2012	131,010	4,922	3,394	180,909	30,152
2013 Activity:					
Extensions and discoveries (8)	52,750	2,306	4,385	92,897	15,483
Revisions of previous estimates	8,114	714	(337)	10,375	1,729
Production	(13,366)	(494)	(515)	(19,417)	(3,237)
Purchases in place	26,961	2,350	7,796	87,832	14,639
Sales in place	(24,759)	—	(5)	(24,791)	(4,132)
Proved reserves as of December 31, 2013	180,710	9,798	14,718	327,805	54,634

(1) Million cubic feet or million cubic feet equivalent, as applicable
(2) Thousand barrels
(3) Oil, condensate 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 oil, condensate or NGLs.
(4) Thousand barrels of oil, condensate or NGLs equivalent.
(5) Natural gas volumes have been converted to equivalent oil, condensate and NGLs volumes using a conversion factor of one barrel of oil, condensate or NGLs to six cubic feet of natural gas.
(6) 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.
(7) The 2012 extensions and discoveries were the result of the extension of proved acreage of the previously discovered Marcellus Shale reservoir through additional drilling during the years subsequent to initial discovery.
(8) 74% of the 2013 extensions and discoveries resulted from successful drilling results in the Marcellus Shale. The remainder of the 2013 extensions and discoveries resulted from the Company's Mid-Continent drilling operations.

Proved Developed and Undeveloped Reserves	Natural Gas (MMcf) (1)	NGLs (MBbl) (2)	Condensate and Oil (MBbl) (2)	MMcfe (1) Equivalents (3)	MBoe (4) Equivalents (5)
December 31, 2011					
Proved developed reserves	65,061	1,339	904	78,518	13,087
Proved undeveloped reserves	26,591	1,418	1,017	41,198	6,867
Total	91,652	2,757	1,921	119,716	19,954
December 31, 2012					
Proved developed reserves	95,602	3,215.8	1,959	126,653	21,109
Proved undeveloped reserves	35,408	1,706	1,435	54,256	9,042
Total	131,010	4,922	3,394	180,909	30,151
December 31, 2013					
Proved developed reserves	114,195	6,025	5,834	185,349	30,892
Proved undeveloped reserves	66,515	3,773	8,884	142,456	23,742
Total	180,710	9,798	14,718	327,805	54,634

(1) Million cubic feet or million cubic feet equivalent, as applicable
(2) Thousand barrels
(3) Oil, condensate 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 oil, condensate or NGLs.
(4) Thousand barrels of oil, condensate or NGLs equivalent.
(5) Natural gas volumes have been converted to equivalent oil, condensate and NGLs volumes using a conversion factor of one barrel of oil, condensate or NGLs to six cubic feet of natural gas.

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, 2013, 2012 and 2011 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 (the "benchmark base prices"). For the periods indicated, the following benchmark base prices for natural gas and oil, before lease adjustments, were used in the calculations:

	For the Years Ended December 31,		
	2013	2012	2011
Natural gas, per MMBtu			
Henry Hub	$3.67	$2.76	$4.12
Oil, per barrel:			
WTI posting	$—	$91.21	$75.96
WTI spot	$96.78	$94.71	$—

These benchmark base 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.

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.

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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, 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 (1)	—	
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	
December 31, 2013:		
Future cash inflows	$2,103,023	
Future production costs	(588,568	)
Future development costs	(296,666	)
Future income taxes	(76,701	)
Future net cash flows	1,141,088	
10% annual discount for estimated timing of cash flows	(625,259	)
Standardized measure of discounted future cash flows	$515,829	

(1) No future taxes payable has been included in the determination of discounted future net cash flows for 2012 due to existing tax loss carry forwards and property tax basis exceeding 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, 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
Extensions and discoveries, less related costs	196,448
Sale of natural gas and oil, net of production costs	(74,394)
Purchases of reserves in place	247,208
Sales of reserves in place	(9,063)
Revisions of previous quantity estimates	6,191
Net change in income tax	(76,701)
Net change in prices and production costs	79,820
Accretion of discount	1,211
Development costs incurred	23,567
Net change in estimated future development costs	(97,461)
Change in production rates (timing) and other	12,194
December 31, 2013	$515,829