Gastar Exploration Inc.
Form 10-K
March 12, 2015
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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, 2014

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 (State or other jurisdiction of incorporation or organization)	38-3531640 (I.R.S. Employer Identification No.)
1331 Lamar Street, Suite 650 Houston, Texas (Address of principal executive offices)	77010 (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, par value $0.001 per share	NYSE MKT LLC
8.625% Series A Cumulative Preferred Stock, par value $0.01 per share	NYSE MKT LLC
10.75% Series B Cumulative Preferred Stock, par value $0.01 per share	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 30, 2014 (the last business day of Gastar Exploration Inc.'s most recently completed second fiscal quarter) was approximately $507.9 million based on the closing price of $8.71 per share on the NYSE MKT LLC.

The total number of shares of common stock, par value $0.001 per share, outstanding as of March 11, 2015 was 80,195,695.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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GASTAR EXPLORATION INC. AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2014
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Form 10-K”) contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements other than statements of historical fact included or incorporated by reference in this Form 10-K are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, future covenant compliance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “poten 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;
- capital expenditures;
- drilling of wells, including the 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 liquidity;
- compliance with covenants under our indenture and credit agreements;
- availability of capital;
- prospect development; and
- property acquisitions and sales.

Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management’s assumptions about future events may prove to be inaccurate. For a more detailed description of the known material factors that could cause actual results to differ from those in the forward-looking statements, see Item 1A. “Risk Factors” in Part I of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for oil, condensate, natural gas and NGLs;
- continued low or further declining prices for oil, condensate, natural gas and NGLs;
- worldwide political and economic conditions and conditions in the energy market;
- the extent to which we are able to realize the anticipated benefits from acquired assets;
- our ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;
- our ability to meet financial covenants under our indenture or credit agreements or the ability to obtain amendments or waivers to effect such compliance;
- 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;
- 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.

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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 Exploration USA, Inc., its direct subsidiary, as part of a reorganization to eliminate Gastar Exploration, Inc.’s holding company corporate structure. Pursuant to the merger agreement, shares of Gastar Exploration, Inc.’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.” Gastar Exploration Inc., together with its subsidiary, owns and continues to conduct Gastar Exploration, Inc.’s business in substantially the same manner as was being conducted prior to the merger.

Unless otherwise indicated or required by the context, (i) for any date or period prior to the January 31, 2014 merger described above,“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 its primary operating company, (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”).

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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 thousand 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 thousand cubic feet of natural gas to one barrel of oil, condensate or NGLs
Boe/d	Barrels of oil equivalent per day
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, calculated on the assumed energy equivalent basis of 6 Mcf of natural gas per MBoe
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, calculated on the assumed energy equivalent basis of 1/6 of a barrel of oil per Mcfe
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, calculated on the assumed energy equivalent basis of 1/6 of a barrel of oil per Mcfe
MMcfe/d	One million cubic feet of natural gas equivalent per day, calculated on the assumed energy equivalent basis of 1/6 of a barrel of oil per Mcfe
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
PBU	Performance based unit
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. In Oklahoma, we are developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and expect to test other prospective formations on the same acreage, including the Woodford Shale and the Meramec Shale (middle Mississippi Lime), which we refer to as the Stack Play. In West Virginia, we are developing liquids-rich natural gas in the Marcellus Shale and have drilled our first successful dry gas Utica Shale/Point Pleasant well on our acreage. We completed the sale of substantially all of our East Texas assets in 2013.
Shares of our common stock are listed on the NYSE MKT LLC under the symbol "GST," shares of our 8.625% Series A Cumulative Preferred Stock are listed on the NYSE MKT LLC under the symbol "GST.PRA" and shares of our 10.75% Series B Cumulative Preferred Stock are listed on the NYSE MKT LLC under the symbol "GST.PRB". 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 decline in oil and 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 assets with a focus on areas that we believe are prospective for natural gas with relatively high condensate and NGLs content;
- additional testing of the Utica Shale;
- 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 and 2014 in partnership with our operating partner in the initial AMI prospect area and two additional adjacent prospect areas. We also increased our exposure within the play through acquisitions of acreage and producing wells from subsidiaries of Chesapeake Energy Corporation and certain entities affiliated with its former chief executive officer (the "Chesapeake Parties") and affiliates of Lime Rock Resources (the "Lime Rock Parties"), respectively, during 2013. 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 and adjacent areas, drilled and completed one gross (0.5 net) horizontal non-operated well during 2012, drilled and completed six gross (3.0 net) horizontal non-operated wells during 2013 and drilled and completed 22 gross (9.8 net) horizontal non-operated wells during 2014 on our Mid-Continent properties. Additionally, during 2013, we began our operated drilling program in the Hunton Limestone with our first two gross (1.8 net) operated wells drilled and completed in the lower Hunton Limestone. During 2014, we drilled and completed seven gross (6.8 net) operated horizontal wells, which includes four gross (3.9 net) wells within the West Edmond Hunton Lime Unit ("WEHLU"). To further test the potential of the formation, we have also participated in three gross (0.4 net) wells outside of our AMI acreage targeting the Hunton Limestone. We are awaiting the completion of two gross (0.1 net) non-operated wells in the Woodford Shale. Prior to 2014, we

participated in a total of two gross (0.1 net) non-operated wells testing the Stack Play potential in the Woodford Shale and the Meramec Shale (middle Mississippi Lime) formations. Production results from these Stack Play wells were below our expectations.

We intend to focus the majority of our 2015 capital budget on drilling existing leasehold, leasehold renewal and leasehold acquisition in the Mid-Continent, with approximately 67% of our 2015 capital budget allocated to developing or maintaining our Hunton Limestone properties. Our 2015 capital budget allocated to the Mid-Continent includes plans to spud a total of 14 gross (12.2 net) wells, comprised of three gross (1.4 net) non-operated wells primarily located within our current AMI and 11 gross (10.8 net) operated WEHLU wells. We anticipate completing a total of 21 gross (16.2 net) wells in the Hunton Limestone during 2015, comprised of eight gross (3.4 net) non-operated wells primarily located within our current AMI and 13 gross (12.8 net) operated WEHLU wells.

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

Due to recent declines in natural gas and NGLs prices in the Appalachian Basin, our 2015 capital program will be limited to completion of certain previously drilled wells. Approximately 26% of our 2015 capital budget is dedicated to Marcellus Shale and Utica well completions and projected purchase of certain additional mineral rights under certain existing acreage. Our 2015 capital budget currently includes plans to complete seven gross (3.5 net) wells in the Marcellus Shale and one gross (0.5 net) well in the Utica Shale. Should well costs decline or net realized prices increase sufficiently, we may elect to expand drilling operations in the area. Our focus continues to be drilling to hold the acreage by production prior to lease term expirations.

Additional Testing of the Utica Shale.

In April 2014, we commenced exploration in the Utica Shale in West Virginia. As anticipated, our initial Utica Shale well, the Simms U-5H, resulted in production of dry natural gas at high delivery rates and levels that may generate attractive internal rates of return despite the absence of liquids. The Simms U-5H was drilled to a total vertical depth of 11,500 feet and with an approximate 4,400-foot lateral and completed with a 25-stage fracture stimulation. The Simms U-5H was producing at a last five-day average rate of 9.1 MMcf/d of natural gas and had total cumulative production of 2.1 Bcf as of February 28, 2015. We spudded our second Utica Shale well, the Blake U-7H, in late November 2014 and completed drilling of the well by mid-December 2014. We currently project that the Blake U-7H will be on production in May 2015.

Actively Manage Our Domestic Drilling Program

We believe that operating approximately 92% of our drilling projects budgeted for 2015 will enable us to control the timing and cost of our drilling as well as control operating costs and the marketing of our production. Cost control is increasingly more important given the current commodity price environment and market conditions. 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 Hunton Limestone, Marcellus Shale and Utica Shale 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 2014. 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, 2014, we held leases covering approximately 225,800 gross (117,800 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. In the initial

AMI, we currently pay 50% of lease acquisition costs for a 50% working interest. We pay 54.25% of the lease acquisition costs in the two additional prospect areas for a 50% working interest. In the initial prospect area, we are currently 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

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activities, and we handle leasing and permitting activities in certain areas of the AMI. For 2015, our focus is to drill in areas that we believe will result in the most significant proved reserve recognition to capital dollars spent and renew acreage in areas that our past drilling has proven to provide attractive returns and production rates and substantial reserve additions. We may elect to sell in the future any acreage that is determined to provide less attractive returns, productions and reserve additions or is outside of our drilling focus to reduce net capital expenditures.

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 gross producing wells for an adjusted cash purchase price of approximately $69.4 million. Effective July 1, 2013, our working interest partner in the 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. 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.

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.

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As of December 31, 2014 and currently as of the date of this report, we had production and drilling operations at various stages on the following non-operated wells in our original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[1] (Boe/d)	Cumulative Production Averages[2] Boe/d	% Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Jett 1-12H	47.4%	3,900	408	231	77%	February 1, 2014	$6.3
Jones 1-21H	48.4%	4,200	449	157	55%	March 2, 2014	$5.6
Liebhart 1-31H	48.8%	4,400	146	71	75%	March 18, 2014	$7.0
Coronado 1-3H	43.6%	4,300	224	127	71%	March 19, 2014	$5.3
Gamebird 1-7H	48.4%	4,400	764	482	76%	April 2, 2014	$5.5
Sieber 1-31H	33.7%	4,400	1,013	438	63%	April 13, 2014	$5.2
Kodiak 1-29H	45.3%	4,300	1,666	507	73%	May 4, 2014	$4.5
Anna Lee 1-30H	50.0%	4,400	220	128	73%	May 20, 2014	$5.1
Vaverka 1-20H	46.6%	4,400	315	170	67%	July 10, 2014	$5.7
Sasquatch 1-23H	44.2%	4,800	581	242	65%	July 27, 2014	$5.6
Jam 1-4H	33.1%	4,900	477	245	58%	August 8, 2014	$5.8
Yeti 1-29H	35.4%	5,000	1,015	334	61%	August 26, 2014	$5.3
Danny Ray 1-30H	40.3%	5,000	415	210	58%	August 29, 2014	$5.8
Cline 1-13H	54.3%	5,100	166	109	77%	September 6, 2014	$5.0
Michael J 1-18H	43.7%	5,000	740	458	66%	September 29, 2014	$5.2
Shimanek 1-2H	48.9%	5,000	1,829	887	64%	October 9, 2014	$6.0
Hobbs Ranch 1-19H	47.0%	4,400	875	556	77%	October 13, 2014	$5.2
Snowman 1-19H	48.9%	4,900	295	188	72%	October 19, 2014	$5.6
Breckenridge 1-2H	25.4%	4,800	207	143	76%	November 7, 2014	$5.0
Bear Claw 1-28H	50.0%	5,000	395	296	70%	November 13,2014	$6.2
Joyce 1-10H[3]	51.7%	5,300	904	519	74%	December 5, 2014	$6.9
Barry 1-6H	47.8%	5,000	427	307	85%	December 13, 2014	$6.0
LB 1-1H	50.0%	4,400	N/A	N/A	N/A	January 23, 2015	$5.0
Boss Hogg 1-14H	42.0%	4,400	N/A	68	60%	February 21, 2015	$7.2
Polar Bear 1-20H	47.6%	4,400	N/A	N/A	N/A	Awaiting completion	$5.0

Falcon 1-5H	51.5%	4,700	N/A	N/A	N/A	Awaiting completion	$5.0
The River 1-22H	28.3%	4,400	N/A	N/A	N/A	Awaiting completion	$5.0
Hubbard 1-23H(4)	57.0%	4,600	N/A	N/A	N/A	Awaiting completion	$5.0
Bigfoot 1-9H	43.0%	4,800	N/A	N/A	N/A	Awaiting completion	$5.0
Bo 1-23H	50.0%	4,900	N/A	N/A	N/A	Awaiting completion	$5.0
Dorothy 1-12H	31.0%	5,000	N/A	N/A	N/A	Awaiting completion	$5.0
Unruh 1-34H	50.0%	4,900	N/A	N/A	N/A	Awaiting completion	$5.0

(1) Represents highest daily gross Boe rate.
(2) Represents gross average production for actual producing days through February 28, 2015.
(3) After payout working interest is 45.0%.
(4) After payout working interest is 49.9%.

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In addition to the wells above, we also participated on a non-operated basis in wells outside of the AMI operated by our AMI partner. As of December 31, 2014 and currently as of the date of this report, we had production and drilling operations at various stages on the following non-operated wells outside of the initial AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[1] (BOE/d)	Cumulative Production Averages[2] BOE/d	Cumulative Production Averages[2] % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Rosemary 1-3H	15.6%	3,400	476	220	55%	February 22, 2014	$5.5
Grizzly 1-4H	8.8%	3,600	387	173	55%	May 1, 2014	$4.8
Niemyer 1-2H	17.7%	5,000	422	248	56%	June 24, 2014	$5.7
Wolf 1-9H	16.1%	3,600	391	279	62%	January 3, 2015	$5.5

(1) Represents highest daily gross Boe rate.

(2) Represents gross average production for actual producing days through February 28, 2015.

As of December 31, 2014 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:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[1] (BOE/d)	Cumulative Production Averages[2] BOE/d	Cumulative Production Averages[2] % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Taborek 22-1H	87.4%	3,000	270	127	37%	March 6, 2014	$10.0
Easton 22-1H	98.3%	4,900	673	318	90%	July 30, 2014	$7.8
Easton 22-2H	98.3%	6,500	855	287	92%	August 5, 2014	$3.9
Horseshoe 3-1H	99.3%	5,100	380	185	35%	September 16, 2014	$7.0
Deer Draw 21-4H	98.3%	5,900	495	413	81%	November 7, 2014	$4.9
Deer Draw 21-5H	98.3%	4,900	344	234	85%	November 9, 2014	$5.0
Warsaw 33-2H	98.3%	4,900	N/A	481	80%	February 12, 2015	$3.5
Warsaw 33-3H	98.3%	5,800	648	277	71%	February 13, 2015	$5.9
Warsaw 33-1[3]	98.3%	N/A	N/A	N/A	N/A	Awaiting completion	$3.5

Easton 22-3H	98.3%	6,500	N/A	N/A	N/A	Drilling	$5.0
Blair Farms 31-1H	98.3%	6,500	N/A	N/A	N/A	Drilling	$3.2

(1) Represents highest daily gross Boe rate.

(2) Represents gross average production for actual producing dates through February 28, 2015.

(3) The Warsaw 33-1 is a vertical well.

We have also participated in four gross (0.2 net) wells outside of our AMI acreage targeting the Woodford Shale and the Mississippi Lime formations.

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.

At December 31, 2014, proved reserves attributable to the Mid-Continent were approximately 34.0 MMBoe, a 92% increase from year-end 2013 reserves. As of December 31, 2014, Mid-Continent proved reserves represented approximately 33% of our total proved reserves and 64% of our SEC total proved PV-10 value. Total Mid-Continent proved reserves at year-end 2014 were comprised of approximately 79% of oil and condensate and NGLs reserves. Approximately 33% of the Mid-Continent year-end 2014 reserves are proved developed.

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

Mid-Continent	For the Years Ended December 31, 2014	2013	2012
Production:			
Oil and condensate (MBbl)	792	189	2
Natural gas (MMcf)	2,822	1,095	1
NGLs (MBbl)	332	23	—
Total Production (MBoe)	1,594	395	2
Oil and condensate (MBbl/d)	2.2	0.5	—
Natural gas (MMcf/d)	7.7	3.0	—
NGLs (MBbl/d)	0.9	0.1	—
Total daily production (MBoe/d)	4.4	1.1	0.01
Average sales price per unit[(1)]:			
Oil and condensate (per Bbl)	$88.84	$94.80	$85.22
Natural gas (per Mcf)	$4.24	$4.75	$3.47
NGLs (per Bbl)	$31.79	$33.06	$36.15
Average sales price per Boe[(1)]	$58.27	$60.53	$75.58
Selected operating expenses (in thousands):			
Production taxes	$2,940	$820	$2
Lease operating expenses	$15,112	$4,019	$33
Transportation, treating and gathering	$40	$3	$—
Selected operating expenses per Boe:			
Production taxes	$1.84	$2.08	$1.22
Lease operating expenses	$9.48	$10.17	$18.79
Transportation, treating and gathering	$0.02	$0.01	$—
Production costs[(2)]	$9.50	$10.17	$18.79

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

For the year ended December 31, 2014, net production from the Mid-Continent averaged 4.4 MBoe/d compared to 1.1 MBoe/d for the year ended December 31, 2013. For the three months ended December 31, 2014, net production from the Mid-Continent averaged 5.6 MBoe/d compared to 4.5 MBoe/d for the three months ended September 30, 2014 and 2.3 MBoe/d for the three months ended December 31, 2013.

Our 2015 Mid-Continent capital budget includes plans to spud a total of 14 gross (12.2 net) wells, comprised of three gross (1.4 net) non-operated wells primarily located within our current AMI and 11 gross (10.8 net) operated wells in the WEHLU. We anticipate completing a total of 21 gross (16.2 net) wells in the Hunton Limestone during 2015, comprised of eight gross (3.4 net) non-operated wells primarily located within our current AMI and 13 gross (12.8 net) operated WEHLU wells.

Appalachian Basin

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, 2014, our acreage position in the play was approximately 74,100 gross (51,300 net) acres. We refer to the approximately 32,100 gross (13,500 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

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Co. Ltd. ("Atinum") as our "Marcellus West acreage." We refer to the approximately 42,100 gross (37,800 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 to optimize our acreage and maximize horizontal lateral lengths.

On September 21, 2010, we entered into the Atinum Joint Venture pursuant to which we ultimately assigned to Atinum, for $70.0 million in total consideration, a 50% working interest in certain undeveloped acreage and shallow producing wells. 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 pursued an initial three-year development program that called for the partners to drill a minimum of 60 operated horizontal wells by year-end 2013. Due to natural gas price declines, we and Atinum agreed to reduce the minimum wells to be drilled requirements from 60 gross wells to 51 gross wells. At December 31, 2014, 67 gross (32.0 net) operated Marcellus Shale horizontal wells were capable of production. All of our Marcellus Shale well operations to date were drilled under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015.

As of December 31, 2014, 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%	40.0%	6,100	Awaiting completion	March 2015
Hoyt(3)	2.0	1.0	50.0%	42.7%	5,000	Awaiting completion	April 2015
Blake(4)	2.0	1.0	50.0%	41.9%	5,700	Awaiting completion	May 2015
	7.0	3.5					

(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 is projected to ultimately have nine gross wells, four of which were initially placed on production in August 2013 and three of which are awaiting completion.

(3) The Hoyt pad is projected to ultimately have seven gross wells.

(4) The Blake pad is projected to ultimately have nine gross wells.

As of December 31, 2014, we had an 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 2015.

From the inception of our operations in the Marcellus Shale in 2011 to late 2013, our operated production and sales in West Virginia were temporarily 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 continually attempted to resolve these issues with operational improvements. Subsequent to 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. In July 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, which claims were settled in June 2014.

At December 31, 2014, proved reserves attributable to the Marcellus Shale were approximately 61.0 MMBoe, a 65% increase from year-end 2013 reserves of 36.9 MMBoe, which represented approximately 60% of our total proved reserves and 34% of PV-10 value. Total Marcellus Shale proved reserves at year-end 2014 were comprised of approximately 45% of oil and condensate and NGLs reserves compared to 34% at year-end 2013. Approximately 41% of the Marcellus Shale year-end 2014 reserves are proved developed compared to 58% at December 31, 2013.

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

	For the Years Ended December 31,		
Marcellus Shale	2014	2013	2012
Production:			
Oil and condensate (MBbl)	182	315	160
Natural gas (MMcf)	8,050	9,594	5,477
NGLs (MBbl)	469	471	270
Total production (MBoe)	1,993	2,385	1,343
Oil and condensate (MBbl/d)	0.5	0.9	0.4
Natural gas (MMcf/d)	22.1	26.3	15.0
NGLs (MBbl/d)	1.3	1.3	0.7
Total daily production (MBoe/d)	5.5	6.5	3.7
Average sales price per unit(1)(2):			
Oil and condensate (per Bbl)	$68.21	$55.61	$62.40
Natural gas (per Mcf)	$4.28	$2.86	$2.33
NGLs (per Bbl)	$23.11	$31.52	$28.22
Average sales price per Boe(1)(2)	$28.97	$25.08	$22.62
Selected operating expenses (in thousands):			
Production taxes(3)	$3,685	$3,805	$2,138
Lease operating expenses(3)	$4,187	$3,181	$2,070
Transportation, treating and gathering(3)	$3,552	$1,176	$1,090
Selected operating expenses per Boe:			
Production taxes(3)	$1.85	$1.60	$1.59
Lease operating expenses(3)	$2.10	$1.33	$1.54
Transportation, treating and gathering(3)	$1.78	$0.49	$0.81
Production costs(4)	$3.50	$1.76	$2.29

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(1) Excludes the impact of hedging activities.

(2) The year ended December 31, 2014 includes the benefit of a non-recurring revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Year Ended December 31, 2014
Marcellus Shale	
Average sales price per unit:	
Oil and condensate (per Bbl)	$50.96
Natural gas (per Mcf)	$3.27
NGLs (per Bbl)	$24.55
Average sales price per Boe	$23.65

(3) The year ended December 31, 2014 includes a non-recurring adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

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	For the Year Ended December 31, 2014
Marcellus Shale	
Selected operating expenses per Boe:	
Production taxes	$1.56
Lease operating expenses	$2.19
Transportation, treating and gathering	$0.99

(4) Production costs include lease operating expense, insurance, transportation, treating and gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the year ended December 31, 2014 would have been as follows:

	For the Year Ended December 31, 2014
Marcellus Shale	
Selected operating expenses per Boe:	
Production costs	$2.80

Our 2015 capital budget includes plans to complete seven gross (3.5 net) wells in the Marcellus Shale. We will continue to monitor prices and services costs, and should well costs decline significantly or higher net realized area product pricing improve, we may elect to resume drilling operations in the area.

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 wells, recent Utica Shale completions by other nearby operators and the drilling and completion of our first horizontal Utica Shale well, we believe that our Marcellus West acreage should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale. We spudded our first Utica Shale well, the Simms U-5H, on April 3, 2014. We drilled the Simms U-5H to a total vertical depth of 11,500 feet and drilled an approximate 4,400-foot lateral and completed it with a 25-stage fracture stimulation. The Simms U-5H was producing at a last five-day average rate of 9.1 MMcf/d of natural gas and had total cumulative production of 2.1 Bcf as of February 28, 2015. Our working interest in the Simms U-5H is 50.0% (43.2% net revenue interest). We spudded our second Utica Shale well, the Blake U-7H, in late November 2014, in which we own a 50% working interest (41.1% net revenue interest). Currently, we are projecting flow back operations will commence in May 2015. At December 31, 2014, one gross (0.5 net) operated Utica Shale horizontal well was capable of production and one gross (0.5 net) operated Utica Shale well was awaiting completion. All of our Utica Shale well operations to date were drilled under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015. For the year ended December 31, 2014, net production from the Utica Shale averaged 0.3 MBoe/d. For the three months ended December 31, 2014, net production from the Utica Shale averaged 1.0 MBoe/d compared to 0.3 MBoe/d for the three months ended September 30, 2014.

At December 31, 2014, proved reserves attributable to the Utica Shale were approximately 7.1 MMBoe, or 7% of our total proved reserves, and were comprised 100% of natural gas reserves. Approximately 12% of the Utica Shale year-end 2014 reserves are proved developed.

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The following table provides production and operational information for the Utica Shale for the period indicated:

Utica Shale	For the Year Ended December 31, 2014
Production:	
Natural gas (MMcf)	725
Total production (MBoe)	121
Natural gas (MMcf/d)	2.0
Total daily production (MBoe/d)	0.3
Average sales price per unit(1):	
Natural gas (per Mcf)	$ 1.68
Average sales price per Boe(1)	$ 10.10
Selected operating expenses (in thousands):	
Production taxes	$ 109
Lease operating expenses	$ 24
Transportation, treating and gathering	$ 87
Selected operating expenses per Boe:	
Production taxes	$ 0.90
Lease operating expenses	$ 0.20
Transportation, treating and gathering	$ 0.72
Production costs(2)	$ 0.92

(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.

Our 2015 capital budget includes plans to complete one gross (0.5 net) well previously drilled in the Utica Shale. We will continue to monitor prices and services costs, and should well costs decline significantly or net realized area product pricing improves, we may elect to resume drilling operations in the area.

Hilltop Area, East Texas

In October 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 adjusted net proceeds of approximately $42.9 million.

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

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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 and Utica Shale 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 October 2013 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 October 2013 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. During December 2014, the gas purchase agreement with SEI was amended to include all of our Wetzel County, West Virginia production in addition to the previously dedicated Marshall County, West Virginia production. 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. From the inception of our operations in the Marcellus Shale in 2011 to late 2013, our operated production and sales in West Virginia were temporarily 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 continually took steps to attempt to resolve these issues with operational improvements. In July 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, which claims were settled in June 2014. In conjunction with the settlement, the SEI and Williams contracts were amended regarding certain fees and operational matters and the contracts were extended through July 1, 2023.

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. As a condition to the sale of our East Texas interests, Cubic Energy, Inc., the purchaser of our East Texas properties, assumed all obligations pursuant to the Hilltop Gathering Agreement.

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, Inc. 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,		
	2014	2013	2012
SEI	50 %	56 %	47 %
Sunoco	37 %	16 %	— %
Clearfield Appalachian	— %	8 %	14 %
ETC	— %	8 %	24 %

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. For more information, 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 oil and natural gas industry is intensely competitive in all of its phases. We encounter competition from other oil and natural gas companies in all areas of our operations. In seeking suitable oil and natural gas properties for acquisition, we compete with other companies operating in our areas of interest, including large oil and natural gas 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 oil and natural gas but also market oil and natural gas and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive oil and natural gas 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. For more information, 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 oil and natural gas 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 is dependent upon weather with prices decreasing during the summer months and increasing 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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

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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 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 oil and natural gas exploration, development 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. Numerous governmental agencies, including the U.S. Environmental Protection Agency ("EPA"), the U.S. Occupational Safety and Health Administration and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. 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; restrict injection of produced water or other regulated fluids into subsurface strata that may contaminate groundwater; 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; and impose liabilities for pollution resulting from our operations. Failure to comply with these environmental and worker health and safety laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations or the issuance of injunctions limiting or prohibiting operations.

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 certain 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, among other things, petroleum, natural gas and natural gas liquids 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 generation, treatment, storage, transportation 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. Although RCRA currently exempts certain oil and natural gas exploration, development 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 oil and natural gas industry in general.

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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, development 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 oil and natural gas exploration, development 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 disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. For example, in Oklahoma, the governor announced in September 2014 the creation of a Coordinating Council on Seismic Activity, the purpose of which is to help researchers, policymakers, regulators and oil and natural gas industry study seismicity in the state, and the Utility and Environment Committee of the Oklahoma House of Representatives also has considered what, if any, correlations exist between disposal wells and seismic activity in the state. Moreover, in September 2014, the Oklahoma Corporation Commission (“OCC”) adopted monitoring and reporting rules for disposal wells in certain seismically-active areas, which rules require operators of disposal wells located in the Arbuckle Formation to record injection pressure and volume measurements on a daily basis and provide such data to the OCC upon request, and further requires, as part of its agency practice, that disposal wells within a six mile radius of designated seismic “areas of interest,” regardless of formation, have their pressures and volumes recorded on a daily basis and provided to the OCC upon request.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil or natural gas 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 or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management (“BLM”) issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. 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.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma 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. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. 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 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. Also, 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 the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing

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

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expenditures for air pollution control equipment or other air emissions related issues. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015 that would revise the National Ambient Air Quality Standard for ozone, recommending a standard between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards protective of public health and public welfare. If the EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Climate Change

Based on findings made by the EPA 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 GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are established by the states. 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 annual 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. 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.

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 to acquire and surrender emission allowances in return for emitting those GHGs. 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. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025.

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 physical effects were to occur, they could have an adverse effect on our exploration, development 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 ("FWS") 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. For example, in March 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Oklahoma , where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies ("WAFWA"), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's

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habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. 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, which delays, costs or restrictions may be significant.

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 natural gas exploration, development 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, development 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 2015. 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, storage, transportation and disposal of naturally occurring radioactive materials. Furthermore, owners, lessees and operators of natural gas and oil properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from and are often based on negligence, trespass, nuisance, strict liability or fraud.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of 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

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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, to only carry loss of production or business interruption insurance related to the William's facilities and plant covering our Marcellus and Utica Shale operations for up to one year. 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, 2015, we had 57 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 oil and natural gas. 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 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.

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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, 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, and recognition of a $23.9 million gain attributable to the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement which resulted in net income of $36.5 million in 2014, we have not been profitable since we started our business. 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. A substantial or extended decline in commodity prices may 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. Recently, commodity prices have declined precipitously as a result of several factors, including increased worldwide supplies, a stronger U.S. dollar, weather factors and strong competition among oil producing countries for market share. Specifically, prices for WTI - other as published by Plains All American have declined from a monthly average of $101.68 per barrel in June 2014 to a monthly average of $44.46 per barrel in January 2015. The Henry Hub spot market price of natural gas has declined from a monthly average of $4.77 per MMBtu in March 2014 to a monthly average of $2.99 per MMBtu in January 2015.

Lower realized 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, but are not limited to:

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

The long-term effect of these and other factors on the prices of oil, condensate, natural gas 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 and our ability to meet our financial covenants under our debt agreements;
- Reducing the amount of oil, condensate, natural gas and NGLs that we can produce economically;

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- 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 oil and natural gas reserves;
- Reducing the carrying value of our oil and natural gas properties;
- Reducing the standardized measure of discounted future net cash flows relating to oil and natural gas reserves;
- Reducing or eliminating our ability to pay dividends on our outstanding preferred stock; 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 2014, approximately 24% of our natural gas production was priced based on the Henry Hub basis point and 76% was priced based on the TETCO M2 basis point. At December 31, 2014, the Henry Hub spot price was $3.14 per MMBtu, compared to the TETCO M2 basis point pricing of $1.74 per MMBtu. 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 2014, approximately 81% and 19% 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 $88.84 and $50.96, respectively, excluding the impact of hedging activities and arbitration settlement for the year. This compares to the daily unweighted average WTI posted price of $89.49 per barrel for 2014. For the year ended December 31, 2014, our realized NGLs prices for Marcellus Shale and Mid-Continent NGLs production represented approximately 27% and 36%, respectively, of the full-year 2014 daily unweighted average WTI - other posted price of $89.49, excluding the impact of hedging activities and arbitration settlement for the year. For the year ended December 31, 2014, our realized natural gas prices for Appalachian Basin and Mid-Continent production excluding the impact of hedging activities and arbitration settlement represented approximately 72% and 98%, respectively, of the full-year 2014 daily unweighted average Henry Hub posted price of $4.34.

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 and to service our indebtedness.

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 2015 totals $102.5 million, and we expect to fund these expenditures using existing cash balances, cash generated internally from our operations, borrowings under our revolving credit facility 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;
- 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 revolving credit facility or our cash flow from operations decreases as a result of lower oil or natural gas prices, operating difficulties, declines in estimated oil and natural gas 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.

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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.

We may not be able to generate sufficient cash or cash flows, as applicable, to service all of our indebtedness or to meet financial covenants under our debt agreements 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 and to meet related financial covenants applicable to our debt instruments, 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.

As of March 9, 2015, the borrowing base under our Revolving Credit Facility was increased to and is currently $200.0 million, and there are $55.0 million in borrowings outstanding under the Revolving Credit Facility. Our next scheduled borrowing base redetermination is expected to occur in November 2015. Our borrowing base is determined semi-annually by our lenders and is based on our proved reserves and the value attributed to those reserves. If commodity prices decline, the borrowing base under our Revolving Credit Facility could be reduced, resulting in a reduction of available credit and the potential requirement for us to repay outstanding indebtedness in excess of the redetermined borrowing base, if any. In addition, 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 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. 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.

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 637,000 Bbls of crude production, 11.4 Bcf of natural gas production and 69,000 Bbls of NGLs production in 2015, 532,000 Bbls of crude production and 1.5 Bcf of natural gas production in 2016, 373,000 Bbls of crude production in

2017, and 103,000 Bbls of crude production in 2018 as of December 31, 2014. Although these hedges may partially protect us from declines in commodity prices, in light of recent significant declines in oil and natural gas prices, the continued benefit these hedges provide will diminish should energy commodities futures market pricing improve. In addition, 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.

Any disruptions in production, development of proved oil and natural gas 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. Approximately 39% of our oil, condensate, natural gas and NGLs revenues before the impact of hedges and approximately 67% of our total proved reserves for the year ended December 31, 2014 were attributable to our properties in the Appalachian Basin. Production in the Appalachian Basin could unexpectedly be disrupted or curtailed due to reservoir, mechanical or third-party gathering system or processing plant 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 operated by Williams. During 2013, our Marcellus Shale production was significantly curtailed due to issues with high line pressures and unscheduled downtime on the gathering system operated by Williams that services our Marcellus West properties.

Approximately 61% of our oil, condensate, natural gas and NGLs revenues, before the impact of hedges, and approximately 33% of our total proved reserves for the year ended December 31, 2014 were attributable to our properties in the Mid-Continent. 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, depends on the proximity of our reserves to and the capacity of natural gas gathering and processing 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 and Utica Shales in the Appalachian Basin of West Virginia and central and southwestern Pennsylvania. For the year ended December 31, 2014, SEI accounted for substantially all of our revenues from the Marcellus Shale. If SEI was to cease purchasing and Williams was to cease gathering, processing or transporting our natural gas in the Appalachian Basin and we were unable to contract with another purchaser and/or gatherer, processor or transporter, it would have a material adverse effect on our financial condition, future cash flows and the results of operations.

Delays in the commencement of operations of new pipelines, the unavailability of 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. We estimate that gathering system downtime during the year ended December 31, 2013 resulted in reduced production of approximately 1.1 MBoe/d, or 13% of total production for the year ended December 31, 2013, which reflected 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. The disputes were subsequently settled between both parties on June 17, 2014.

In West Virginia and southwestern Pennsylvania, key issues to development include, but are not limited to, 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 oil and natural gas 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.

Legislation or regulatory initiatives intended to address seismic activity could increase our costs of compliance and delay or restrict our ability to dispose of produced water generated by our drilling and production operations, which could have a material adverse effect on our business, results of operations and financial condition.

We inject into disposal wells significant volumes of produced water generated in connection with our drilling and production operations, pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such disposal activities. There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic activity in certain areas, including Oklahoma, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in Oklahoma, the governor announced in September 2014 the creation of a Coordinating Council on Seismic Activity, the purpose of which is to help researchers, policymakers, regulators and oil and natural gas industry study seismicity in the state, and the Utility and Environment Committee of the Oklahoma House of Representatives also has considered what, if any, correlations exist between disposal wells and seismic activity in the state. Moreover, in September 2014, the Oklahoma Corporation Commission ("OCC") adopted monitoring and reporting rules for disposal wells in certain seismically-active areas, which rules require operators of disposal wells located in the Arbuckle Formation to record injection pressure and volume measurements on a daily basis and provide such data to the OCC upon request, and further requires, as part of its agency practice, that disposal wells within a six mile radius of designated seismic "areas of interest," regardless of formation, have their pressures and volumes recorded on a daily basis and provided to the OCC upon request.

Approximately 64% of our proved reserves are classified as proved developed non-producing or proved undeveloped at December 31, 2014 and may ultimately prove to be less than current reserves estimates.

At December 31, 2014, approximately 64% of our total proved reserves were classified as proved developed non-producing or proved undeveloped. It will take approximately $602.2 million of capital to re-complete or drill our non-producing and undeveloped locations. Our estimate of proved reserves at December 31, 2014 assumes that we will spend in 2015 and 2016 development capital expenditures to develop these reserves of $36.6 million and $141.7 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. Absent significant price increases, the sustained lower oil and natural gas prices experienced in the second half of 2014 and the current year will continue to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices, which were substantially higher at December 31, 2014 than current oil and natural gas prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn may make it more likely that we will incur impairment charges in the future against our oil and natural gas properties under full cost accounting. In addition, oil and natural gas prices sustained at current or lower levels and the resultant impact such prices may have on our drilling economics and our ability to raise capital could require us to re-evaluate and postpone our development drilling, which could result in the reduction of some of our proved undeveloped reserves.

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 oil and natural gas 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 oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Further, we may not be successful in exploring for, developing or acquiring additional reserves, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

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

Our future success will largely depend on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the risk that no commercially productive 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 or natural resource damages;

- 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;

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- Adverse weather conditions;
- Compliance with existing and any future governmental laws and regulations; 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 transportation and 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.

You should not consider the present values of estimated future net cash flows referred to in this Form 10-K to be the current market value of the estimated reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves for all periods from 2010 to 2014 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 report, the net present value of estimated future net revenues of our proved reserves at December 31, 2014 is calculated using the historical 12-month unweighted arithmetic average of the first-day-of-the-month prices which are substantially above current oil and natural gas prices. These average prices and the 10% discount rate are not necessarily the

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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 oil and natural gas 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 similar to the current market. 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. Absent significant price increases, the sustained lower oil and natural gas prices experienced in the second half of 2014 and the current year will continue to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices, which were substantially higher at December 31, 2014 than current oil and natural gas prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn may make it more likely that we will incur impairment charges in the future against our oil and natural gas properties under full cost accounting.

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 or Mid-Continent area 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 oil and natural gas wells and adversely affect our production” for a discussion of legislative and regulatory initiatives that could significantly restrict hydraulic fracturing and therefore make it more difficult or costly for us to perform hydraulic fracturing.

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

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

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

As of December 31, 2014, 145 gross (34.0 net) wells in which we have an interest were operated by other companies.

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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.

For more information, see Item 8. “Financial Statements and Supplementary Data, 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 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.

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 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 regarding our legal proceedings, see Item 8. “Financial Statements and Supplementary Data, Note 14. Commitments and Contingencies.”

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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, development 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:

- 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 December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015 that would seek to reduce the National Ambient Air Quality Standard for ozone to between 65 and 70 ppb for both the 8-hour primary and secondary standards. Compliance with these or other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our expenditures and operating costs, which could adversely impact our business.

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 oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons 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 natural gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.

Also, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma 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. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. 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 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. Also, 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 in the first half of 2015. These existing or any future studies, depending on their results, could spur initiatives to regulate hydraulic fracturing.

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 our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our 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.

We may not be able to recover some or any of these costs from insurance.

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

- Well blowouts, fires and explosions;
- Surface craterings and casing collapses;
- Road collapses;
- Uncontrollable flows of natural gas, oil, brine, water or well fluids;
- Pipe and cement failures;

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- 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 discharges 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 2016 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.

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

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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 trade-execution. In addition, the CFTC and bank regulators have proposed margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception to both the mandatory clearing and margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects.

The 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 or reduce our ability to monetize or restructure our existing derivatives contracts. 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.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

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.

Based on findings made by the EPA 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 GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically will be established by the states. In addition, the EPA adopted rules requiring the monitoring and annual reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities. Congress has from time to time considered legislation to reduce emissions of GHGs, but 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 to acquire and surrender emission allowances in return for emitting those GHGs. 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. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025. 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.

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 seven 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 oil and natural gas 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 oil and natural gas 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 Certificate 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 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. We have issued in the past, and may in the future continue to issue, in the open market at prevailing prices or in capital markets offerings series of perpetual preferred stock with dividend and liquidation preferences that rank ahead 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.

If commodity prices continue to drop, we may be limited or unable to lawfully declare dividends on our capital stock.

The Delaware General Corporation Law (the "DGCL") permits payment of dividends out of a corporation's surplus. Surplus is defined as the excess of net assets over the corporation's capital as determined under the DGCL. If commodity prices continue to drop, the net value of our assets will decline and, accordingly, we may not have available surplus from which to lawfully pay or declare dividends on our capital stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

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

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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.

	For the Years Ended December 31,		
	2014	2013	2012
Production:			
Oil and condensate (MBbl)	975	515	177
Natural gas (MMcf)	11,598	13,366	10,564
NGLs (MBbl)	801	494	270
Total production (MBoe)	3,708	3,236	2,208
Daily Production:			
Oil and condensate (MBbl/d)	2.7	1.4	0.5
Natural gas (MMcf/d)	31.8	36.6	28.9
NGLs (MBbl/d)	2.2	1.4	0.7
Total daily production (MBoe/d)	10.2	8.9	6.0
Average sales price per unit(1):			
Oil and condensate per Bbl, excluding impact of hedging activities	$84.98	$70.91	$65.45
Oil and condensate per Bbl, including impact of hedging activities(2)	$83.86	$71.04	$70.01
Natural gas per Mcf, excluding impact of hedging activities	$4.11	$3.02	$2.21
Natural gas per Mcf, including impact of hedging activities(2)	$3.84	$3.43	$3.20
NGLs per Bbl, excluding impact of hedging activities	$26.71	$31.59	$28.22
NGLs per Bbl, including impact of hedging activities(2)	$26.53	$31.13	$34.40
Average sales price per Boe, excluding impact of hedging activities	$40.95	$28.58	$19.26
Average sales price per Boe, including impact of hedging activities(2)	$39.78	$30.20	$25.14
Selected operating expenses (in thousands):			
Production taxes(3)	$6,733	$4,651	$2,269
Lease operating expenses(3)	$19,323	$9,456	$6,174
Transportation, treating and gathering(3)	$3,679	$4,006	$4,965
Depreciation, depletion and amortization	$46,180	$32,449	$25,424
Impairment of natural gas and oil properties	$—	$—	$150,787
General and administrative expense	$16,485	$16,961	$12,211
Selected operating expenses per Boe:			
Production taxes(3)	$1.82	$1.44	$1.03
Lease operating expenses(3)	$5.21	$2.92	$2.80
Transportation, treating and gathering(3)	$0.99	$1.24	$2.25
Depreciation, depletion and amortization	$12.45	$10.02	$11.52
General and administrative expense(4)	$4.45	$5.24	$5.53
Production costs(5)	$6.00	$4.05	$4.81

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(1)The year ended December 31, 2014 includes the benefit of a non-recurring revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Year Ended December 31, 2014
Average sales price per unit:	
Oil and condensate per Bbl, excluding impact of hedging activities	$ 81.75
Oil and condensate per Bbl, including impact of hedging activities (2)	$ 80.63
Natural gas per Mcf, excluding impact of hedging activities	$ 3.41
Natural gas per Mcf, including impact of hedging activities (2)	$ 3.14
NGLs per Bbl, excluding impact of hedging activities	$ 27.55
NGLs per Bbl, including impact of hedging activities (2)	$ 27.37
Average sales price per Boe, excluding impact of hedging activities	$ 38.09
Average sales price per Boe, including impact of hedging activities (2)	$ 36.92

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

(3)The year ended December 31, 2014 includes a non-recurring adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

	For the Year Ended December 31, 2014
Selected operating expenses per Boe:	
Production taxes	$ 1.66
Lease operating expenses	$ 5.26
Transportation, treating and gathering	$ 0.56

(4) General and administrative expenses include non-recurring costs related to acquisitions, severance related to property divestment and corporate migration of $263,000, $4.2 million and $834,000 for the years ended December 31, 2014, 2013 and 2012, respectively. Excluding such costs, general and administrative expenses would have been $4.37 per Boe, $3.95 per Boe and $5.15 per Boe for each respective year.

(5)Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the year ended December 31, 2014 would have been as follows:

	For the Year Ended December 31, 2014
Selected operating expenses per Boe:	
Production costs	$ 5.62

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Drilling Activity

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

	For the Years Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	30.0	14.9	11.0	5.7	6.0	1.7
Non-productive	—	—	—	—	—	—
Total	30.0	14.9	11.0	5.7	6.0	1.7
Development wells:						
Productive	11.0	6.0	17.0	8.5	31.0	14.2
Non-productive	—	—	—	—	—	—
Total	11.0	6.0	17.0	8.5	31.0	14.2

On December 31, 2014, we had a total of seven gross (3.5 net) operated wells in the process of being drilled or awaiting fracture stimulation in the Marcellus Shale, one gross (0.5 net) operated well in the process of being drilled or awaiting fracture stimulation in the Utica Shale and three gross (2.9 net) operated wells and ten gross (4.5 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, 2014.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Appalachian Basin, West Virginia and Pennsylvania(1)				
Marcellus West(2)(3)	21,031	8,718	11,030	4,746
Marcellus East	38,869	34,870	3,185	2,936
Total Marcellus Shale area	59,900	43,588	14,215	7,682
Mid-Continent	156,613	74,397	69,159	43,439
Total	216,513	117,985	83,374	51,121

(1) We believe that substantially all of our Appalachian Basin acreage is prospective.

(2) The Marcellus West acreage reflects that Atinum has earned their full joint venture interest.

(3) Approximately 27,900 gross (11,500 net) acres of our Marcellus West acreage, of which approximately 4,300 gross (1,900 net) acres are pending lease finalization, should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale.

Undeveloped Acreage Expirations

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

As of December 31,	Appalachian Basin			Total Expiring	% of Total Undeveloped	
	West	East	Mid-Continent	Gross Acres	Gross Acres	
2015	3,354	9,635	47,687	60,676	28	%
2016	2,981	13,315	80,014	96,310	44	%
2017	5,131	52	28,628	33,811	16	%
2018	5,813	7	242	6,062	3	%
2019 and thereafter	2,466	—	42	2,508	1	%

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

As of December 31,	Appalachian Basin			Total Expiring	% of Total Undeveloped
	West	East	Mid-Continent	Net Acres	Net Acres
2015	1,375	9,385	21,166	31,926	27 %
2016	1,517	10,945	35,581	48,043	41 %
2017	1,823	52	17,370	19,245	16 %
2018	2,092	7	217	2,316	2 %
2019 and thereafter	1,234	—	63	1,297	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 approximately 31,900 net undeveloped acres expiring in 2015, we are currently focusing on net acres expiring in Marcellus West and the Mid-Continent. In Marcellus West, completion of currently drilled wells will hold by production the majority of the acreage before it expires. In the Mid-Continent, approximately 11,700 net acres, or 55%, 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 majority of the automatic lease extension payments. We also plan to extend the leases for any additional acreage expiring during 2015 in the Mid-Continent that do not have automatic lease extensions that we have determined to be in areas that are the focus of our drilling operations. If we are not able to extend the lease, the acreage will expire. We may in the future sell Mid-Continent acreage that we deem to be non-strategic. Our current plans in Marcellus East is to let the approximately 9,400 net undeveloped acres scheduled for expiration in 2015 expire.

Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2014. 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
Appalachian Basin, West Virginia and Pennsylvania	110.0	53.1	—	—	110.0	53.1
Mid-Continent, Oklahoma	177.0	84.0	58.0	44.3	235.0	128.3
Total	287.0	137.1	58.0	44.3	345.0	181.4

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 and in the application of the "ceiling test" for determining impairment of oil and natural gas properties under full cost accounting. The unweighted 12-month average commodity prices used in determining December 31, 2014 estimates of proved reserves and related PV-10 and standardized measure of future net cash flows are substantially above current oil and natural gas prices. Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

Third Party Review of Reserves Estimates

For the years ended December 31, 2014 and 2013, reserves estimates for the Appalachian Basin and Mid-Continent area 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 both of our operating areas. 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 40 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 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 historically 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 30 years. During the year, our technical team may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operational conditions.

Technologies Used in Reserves Estimation

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

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Estimated Proved Reserves

Our proved reserves information as of December 31, 2014 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.

In accordance with SEC regulations, estimates of our proved reserves and future net revenues as of December 31, 2014 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 $4.35 per MMBtu for natural gas and a WTI spot oil price of $94.99 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 oil and natural gas prices, which are highly volatile. Toward the end of 2014, oil and natural gas prices declined precipitously and current market prices are more than 50% and 30% lower than the key benchmark average prices used as of December 31, 2014 for oil and natural gas, respectively. All of our proved reserves are located onshore within the U.S.

The following table summarizes our estimated proved reserves as of December 31, 2014:

	Total Proved Reserves			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	114,101	463	172,441	287,005
NGLs (MBbls)	10,706	21	14,866	25,593
Oil and condensate (MBbls)	6,967	1	21,668	28,636
Total proved reserves (MBoe)	36,690	99	65,274	102,063
PV-10 (in thousands)(1)	$444,765	$(483)	$544,404	$988,686
Standardized measure of discounted future net cash flows(1)				$816,739

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(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. At December 31, 2014, we presently have approximately $447.0 million of net operating loss carryforwards, $50.7 million of foreign tax credit carryforwards and $357.5 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 $171.9 million, resulting in a standardized measure of discounted future net cash flows of $816.7 million as of December 31, 2014.

The following table summarizes our proved reserves by geographic area as of December 31, 2014:

SEC Pricing Case Proved Reserves(1)

	Natural Gas (MMcf)	NGLs (MBbls)	Oil and Condensate (MBbls)	MBoe	% Proved Developed	PV-10	Standardized Measure of Discounted Future Net Cash Flows

							(in thousands)	
Appalachian Basin, West Virginia and Pennsylvania	244,141	19,309	8,067	68,066	38	%	$353,507	
Mid-Continent	42,864	6,284	20,569	33,997	33	%	635,179	
Total	287,005	25,593	28,636	102,063	36	%	$988,686	$816,739

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(1) Key benchmark base prices utilized were the Henry Hub price of $4.35 per MMBtu for natural gas and a WTI spot oil price of $94.99 per barrel.

Proved Undeveloped Reserves ("PUDs")

As of December 31, 2014, our PUDs totaled 65.3 MMBoe, representing a 175% increase from our PUDs as of December 31, 2013. As of December 31, 2014, 42.5 MMBoe of PUDs were associated with the Appalachian Basin and 22.8 MMBoe of PUDs were associated with the Mid-Continent. The December 31, 2014 PUDs consisted of 68 gross (34.0 net) Marcellus Shale horizontal wells, five gross (2.5 net) Utica Shale wells and 132 gross (95.8 net) wells in the Mid-Continent. The increase in PUD well locations in 2014 is due to the successful Marcellus and Utica Shale drilling programs and successful results of our Mid-Continent drilling program in 2014, partially offset by 2.3 MMBoe of 2013 PUD reserves that we converted to proved developed reserves in 2014 through the completion of seven gross (3.5 net) Marcellus Shale wells and five gross (2.8 net) Mid-Continent wells. The net cost of converting such PUDs to proved developed reserves during 2014 was $36.9 million.

The following table summarizes our PUD activity during the year ended December 31, 2014:

	Natural Gas (MMcf)	NGLs (MBbls)	Oil and Condensate (MBbls)	MBoe
PUDs as of December 31, 2013	66,516	3,773	8,884	23,743
Extensions and discoveries	115,042	8,201	10,618	37,993
Purchases of reserves in place	—	—	—	—
PUDs converted to proved developed	(9,450)	(532)	(181)	(2,288)
Revisions of previous estimates	333	3,424	2,347	5,826
PUDs as of December 31, 2014	172,441	14,866	21,668	65,274

Estimated future development costs relating to the development of 2014 year-end PUDs is $594.2 million, of which 2015 and 2016 expenditures are $36.6 million and $141.7 million, respectively, resulting in the drilling of 22 gross (10.6 net) and 53 gross (32.3 net) PUD locations, 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, 2014 are scheduled to be drilled by 2019, 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. In addition, oil and natural gas prices sustained at current or lower levels and the resultant impact such prices may have on our drilling economics and our ability to raise capital could require us to re-evaluate and postpone our development drilling, which could result in the reduction or elimination of some of our proved undeveloped reserves.

Item 3. Legal Proceedings

Information about our legal proceedings is set forth in Item 8. "Financial Statements and Supplementary Data, Note 14, Commitments and Contingencies – Litigation" of this Form 10-K.

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.

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	NYSE MKT LLC	
	High	Low
2014:		
Fourth quarter	$6.09	$2.11
Third quarter	$8.75	$5.85
Second quarter	$9.10	$5.72
First quarter	$7.13	$5.05
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

The last reported sale price of our common stock on the NYSE MKT on March 11, 2015 was $2.37. 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 10, 2015, there were 260 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 Notes and Revolving Credit Facility prohibits us from paying cash dividends on our common stock as long as any debt remains outstanding under the facility.

We intend to 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. For the year ended December 31, 2014, preferred dividends paid totaled $14.4 million.

Issuer Purchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans	(d) Maximum Number of Shares that May Yet be Purchased Under the Plan
January 1, 2014 - January 31, 2014	549,571	$5.80	—	n/a
March 1, 2014 - March 31, 2014	88,090	$5.28	—	n/a
June 1, 2014 - June 30, 2014	410	$7.32	—	n/a
August 1, 2014 - August 31, 2014	7,967	$6.63	—	n/a
November 1, 2014 - November 30, 2014	204,096	$4.18	—	n/a

Shares purchased represent shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock units held by our employees and Board of Directors.

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Recent Sales of Unregistered Securities

We did not have any sales of unregistered securities during the year ended December 31, 2014.

Item 6. Selected Financial Data

The following table presents selected historical financial data as of and for the periods indicated. The selected consolidated financial data are derived from our audited consolidated financial statements. The following selected historical 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, 2014 includes a gain of $23.9 million for the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement benefit. 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 year ended December 31, 2012 includes impairment of oil and natural gas properties of $150.8 million. 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.

	As of and for the Years Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per share data)				
Consolidated Statements of Operations:					
Revenues	$171,418	$87,755	$49,940	$40,235	$42,768
Income (loss) from operations	$78,512	$18,764	$(153,528)	$(631)	$(15,019)
Net income (loss) attributable to Common Stockholders	$36,529	$39,964	$(160,868)	$(1,764)	$(12,460)
Net income (loss) attributable to Common Stockholders per share:					
Basic	$0.58	$0.66	$(2.53)	$(0.03)	$(0.25)
Diluted	$0.55	$0.63	$(2.53)	$(0.03)	$(0.25)
Weighted average shares of common stock outstanding					
Basic	63,271	60,220	63,538	63,004	49,814
Diluted	66,493	63,618	63,538	63,004	49,814
Consolidated Balance Sheets:					
Property, plant and equipment, net	$692,300	$517,513	$256,251	$285,740	$215,115
Total assets	$775,794	$589,935	$290,068	$334,503	$247,352
Long-term liabilities	$370,480	$325,802	$106,020	$39,438	$14,295
Total stockholders’ equity	$350,286	$210,029	$126,536	$235,194	$207,391

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. and its subsidiaries as of and for the years ended December 31, 2014,2013 and 2012and the notes thereto included elsewhere in this Form 10-K.

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. In Oklahoma, we are developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and expect to test other prospective formations on the same acreage, including the Woodford Shale and the Meramec Shale (middle Mississippi Lime), which we refer to as the Stack Play. In West Virginia, we are developing liquids-rich natural gas in the Marcellus Shale and have drilled and completed our first successful dry gas Utica Shale/Point Pleasant well on our acreage. We completed the sale of substantially all of our East Texas assets in 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 subsidiary, owns and continues to conduct Gastar’s business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger.

All of our current operational activities are conducted in the U.S. As of December 31, 2014, our major assets consist of approximately 74,100 gross (51,300 net) acres in the Appalachian Basin in West Virginia and southwestern Pennsylvania and approximately 225,800 gross (117,800 net) acres in the Mid-Continent area of the U.S. in the state of Oklahoma. During the past three years, we spent approximately $727.1 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 during 2014 primarily due to the recognition of a gain of $23.9 million for the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement benefit, and during 2013 primarily due to the recognition of a gain on acquisition of assets at fair value, net of taxes, of $27.7 million and the related income tax benefit for acquisition of $16.0 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, Utica 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.

2014 Highlights

Mid-Continent Horizontal Oil Play. At December 31, 2014, we held leases covering approximately 225,800 gross (117,800 net) acres in the Mid-Continent horizontal oil play and completed seven gross (6.8 net) operated wells and 25 gross (10.2 net) non-operated wells. At December 31, 2014, our proved reserves attributable to our Mid-Continent acreage were approximately 34.0 MMBoe. Mid-Continent proved reserves represented approximately 33% of our total proved reserves and approximately 64% of our pre-tax PV-10 value at December 31, 2014. Oil, condensate and NGLs reserves comprised approximately 79% of the total Mid-Continent proved reserves at year end 2014.

Utica Shale/Point Pleasant Drilling Program. At December 31, 2014, we held leases covering approximately 27,900 gross (11,500 net) acres in the Marcellus Shale that have Utica Shale/Point Pleasant potential, of which approximately 4,300 gross (1,900 net) acres are pending lease finalization. During 2014, we drilled and completed our first Utica Shale well, the Simms U-5H, to a total vertical depth of 11,500 feet with an approximate 4,400 foot lateral. The well began production on August 27, 2014 and produced at an initial 48-hour gross sales rate of 29.4 MMcf/d of natural gas. The Simms U-5H was producing at a last five-day average rate of 9.1 MMcf/d of natural gas and had total cumulative production of 2.1 Bcf as of

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February 28, 2015. We spudded our second Utica Shale well, the Blake U-7H, on November 13, 2014 and completed drilling the well on December 11, 2014. The Blake U-7H was drilled to a total vertical depth of 11,100 feet with an approximate 6,600 foot lateral. The Blake U-7H is currently projected to be completed in May 2015. Our working interest in the Utica Shale wells is 50% (approximate net revenue interest 43.2%). At December 31, 2014, our proved reserves attributable to the Utica Shale acreage were approximately 42.7 Bcf of natural gas. Utica Shale proved reserves represented approximately 7% of our total proved reserves at December 31, 2014.

Marcellus Shale Drilling Program. During the year ended December 31, 2014, we drilled and completed 10 gross (5.0 net) operated wells in Marshall County, West Virginia, under the Atinum Joint Venture and had 7 gross (3.5 net) operated wells drilled and awaiting completion of which our current plans are to complete 5 gross (2.5 net) wells pending improvement in area realized natural gas prices and/or lower completion service costs. At December 31, 2014, we had 67 gross (32.0 net) operated wells on production in Marshall County, West Virginia. At December 31, 2014, our proved reserves attributable to our Marcellus Shale acreage were approximately 61.0 MMBoe, a significant increase from year-end 2013 reserves of 36.9 MMBoe. Marcellus Shale proved reserves represented approximately 60% of our total proved reserves and approximately 34% of our pre-tax PV-10 value at December 31, 2014. Oil, condensate and NGLs reserves comprised approximately 45% of the total Marcellus Shale proved reserves at year end 2014.

Financial Highlights

Our consolidated financial statements reflect total revenue of $171.4 million on total volumes of 3.7 MMBoe for the year ended December 31, 2014. Our operating income for the year ended December 31, 2014 was $78.5 million and included a gain of $23.9 million resulting from the change in mark to market of commodity derivatives contracts still held at year-end and depreciation, depletion and amortization expense of $46.2 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 are included in Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

For additional information about production volumes, prices of oil and natural gas 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,		
	2014	2013	2012
	(In thousands, except per unit amounts)		
Revenues:			
Oil and condensate	$82,820	$36,480	$11,570
Natural gas	47,647	40,416	23,318
NGLs	21,382	15,611	7,630
Gain (loss) on commodity derivatives contracts	19,569	(4,752)	7,422
Total revenues	$171,418	$87,755	$49,940
Production:			
Oil and condensate (MBbl)	975	515	177
Natural gas (MMcf)	11,598	13,366	10,564
NGLs (MBbl)	801	494	270
Total production (MBoe)	3,708	3,236	2,208
Oil and condensate (MBbl/d)	2.7	1.4	0.5
Natural gas (MMcf/d)	31.8	36.6	28.9
NGLs (MBbl/d)	2.2	1.4	0.7
Total daily production (MBoe/d)	10.2	8.9	6.0
Average sales price per unit[1]:			
Oil and condensate per Bbl, excluding impact of hedging activities	$84.98	$70.91	$65.45
Oil and condensate per Bbl, including impact of hedging activities[2]	$83.86	$71.04	$70.01
Natural gas per Mcf, excluding impact of hedging activities	$4.11	$3.02	$2.21
Natural gas per Mcf, including impact of hedging activities[2]	$3.84	$3.43	$3.20
NGLs per Bbl, excluding impact of hedging activities	$26.71	$31.59	$28.22
NGLs per Bbl, including impact of hedging activities[2]	$26.53	$31.13	$34.40
Average sales price per Boe, excluding impact of hedging activities	$40.95	$28.58	$19.26
Average sales price per Boe, including impact of hedging activities[2]	$39.78	$30.20	$25.14
Selected operating expenses (in thousands):			
Production taxes[3]	$6,733	$4,651	$2,269
Lease operating expenses[3]	$19,323	$9,456	$6,174
Transportation, treating and gathering[3]	$3,679	$4,006	$4,965
Depreciation, depletion and amortization	$46,180	$32,449	$25,424
Impairment of natural gas and oil properties	$—	$—	$150,787
General and administrative expenses[4]	$16,485	$16,961	$12,211
Selected operating expenses per Boe:			
Production taxes[3]	$1.82	$1.44	$1.03
Lease operating expenses[3]	$5.21	$2.92	$2.80
Transportation, treating and gathering[3]	$0.99	$1.24	$2.25
Depreciation, depletion and amortization	$12.45	$10.02	$11.52
General and administrative expenses[4]	$4.45	$5.24	$5.53

Production costs[5]	$6.00	$4.05	$4.81

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(1)The year ended December 31, 2014 includes the benefit of a non-recurring revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Year Ended December 31, 2014
Average sales price per unit:	
Oil and condensate per Bbl, excluding impact of hedging activities	$ 81.75
Oil and condensate per Bbl, including impact of hedging activities (2)	$ 80.63
Natural gas per Mcf, excluding impact of hedging activities	$ 3.41
Natural gas per Mcf, including impact of hedging activities (2)	$ 3.14
NGLs per Bbl, excluding impact of hedging activities	$ 27.55
NGLs per Bbl, including impact of hedging activities (2)	$ 27.37
Average sales price per Boe, excluding impact of hedging activities	$ 38.09
Average sales price per Boe, including impact of hedging activities (2)	$ 36.92

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

(3)The year ended December 31, 2014 includes a non-recurring adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

	For the Year Ended December 31, 2014
Selected operating expenses per Boe:	
Production taxes	$ 1.66
Lease operating expenses	$ 5.26
Transportation, treating and gathering	$ 0.56

(4) General and administrative expenses include non-recurring costs related to acquisitions, severance related to property divestment and corporate migration of $263,000, $4.2 million and $834,000 for the years ended December 31, 2014, 2013 and 2012, respectively. Excluding such costs, general and administrative expenses would have been $4.37 per Boe, $3.95 per Boe and $5.15 per Boe for each respective year.

(5)Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the year ended December 31, 2014 would have been as follows:

	For the Year Ended December 31, 2014
Selected operating expenses per Boe:	
Production costs	$ 5.62

Year Ended December 31, 2014 compared to Year Ended December 31, 2013

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $151.8 million for the year ended December 31, 2014, up 64% from $92.5 million for the year ended December 31, 2013. The increase in revenues was the result of a 43% increase in weighted average realized prices coupled with a 15% increase in production. Average daily production on an equivalent basis was 10.2 MBoe/d for the year ended December 31, 2014 compared to 8.9 MBoe/d for the same period in 2013. During 2014, production in the Appalachian Basin averaged 5.8 MBoe/d compared to 2013 production of 6.5 MBoe/d, an 11% decrease. The decrease in Appalachian Basin production was due to the only new Marcellus wells not being added until late December 2014 coupled with one Utica Shale well being placed on production in late August 2014. Appalachian Basin production for the year ended December 31, 2014 includes 0.3 MBoe/d of Utica Shale production. For the year ended December 31, 2014, production in the Mid-Continent averaged 4.4 MBoe/d compared to 2013 production of 1.1 MBoe/d. Total company oil, condensate and NGLs production represented approximately 48% of total production for the year ended December 31, 2014 compared to 31% of total production for the year ended December 31, 2013.

Liquids revenues (oil, condensate and NGLs) represented approximately 69% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2014 compared to approximately 56% for the year ended December 31, 2013. We are continuing to focus our drilling activity in the Mid-Continent oil play and the liquids-rich portions of the Marcellus Shale. If current trends of natural gas prices relative to oil, condensate and NGLs prices continue, and assuming that we successfully and timely complete our 2015 drilling activity, we expect our liquids revenues to continue to increase as a percentage of total oil, condensate, natural gas and NGLs revenues in 2015.

During the year ended December 31, 2014, we had commodity derivative hedge contracts covering approximately 48% of our oil and condensate production. The impact of oil commodity derivative contracts settled during the year for oil and condensate sales was a decrease of $1.1 million in oil and condensate revenues resulting in a decrease in total price realized from $84.98 per Bbl to $83.86 per Bbl. The losses on oil and condensate commodity derivatives contracts settled during the year include a loss of $36,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on oil and condensate sales was a decrease in revenues of $1.1 million, which was comprised of $981,000 of NYMEX hedge losses and the payment of $72,000 of deferred put premiums. During the year ended December 31, 2013, the impact of hedging contracts settled during the year for 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 2013 hedge impact included a loss of $2,000 of non-cash amortization of prepaid premiums and 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, 2014, we had commodity derivative contracts covering approximately 84% of our natural gas production, which resulted in losses on natural gas commodity derivatives contracts settled during the year of $3.1 million and a decrease in total price realized from $4.11 per Mcf to $3.84 per Mcf. The losses on commodity derivatives contracts settled during the year include a loss of $317,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was a decrease in revenues of $2.8 million, which was comprised of $3.0 million of NYMEX hedge losses partially offset by $213,000 of regional basis gains. During the year ended December 31, 2013, the impact of hedging contracts settled during the year for natural gas sales was an increase of $5.4 million in natural gas revenues resulting in an increase in total price realized from $3.02 per Mcf to $3.43 per Mcf. The 2013 hedge impact included a loss of $27,000 of non-cash amortization of prepaid premiums.

During the year ended December 31, 2014, we had commodity derivative hedge contracts covering approximately 78% of our NGLs production. The impact of hedging contracts settled during the year for NGLs sales was a decrease of $143,000 in NGLs revenues resulting in a decrease in total price realized from $26.71 per Bbl to $26.53 per Bbl. The NGLs commodity derivatives contracts settled during the year include a loss of $36,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on NGLs sales was a decrease in revenues of $107,000, which was comprised of $35,000 of NYMEX hedge losses coupled with the payment of deferred put premiums of $72,000. During the year ended December 31, 2013, the impact of hedging contracts settled during the year for 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 2013 hedge impact included a loss of $2,000 for non-cash amortization of prepaid premiums and payment of deferred put premiums of $83,000.

Gains related to the change in mark to market value for outstanding commodity derivatives contracts for the year ended December 31, 2014 were $23.9 million compared to losses of $10.0 million for the year ended December 31, 2013. The significant change in the mark to market value is primarily the result of lower future commodity hedge prices and changes in hedge contracts during the period compared to the prior year.

Production taxes. We reported production taxes of approximately $6.7 million for the year ended December 31, 2014, up from $4.7 million for the year ended December 31, 2013. Production taxes for the year ended December 31, 2014 include $584,000 of additional production taxes attributed to a one-time revenue adjustment resulting from an arbitration settlement. Excluding the non-recurring adjustment, the increase in production taxes is primarily the result of higher revenues in Oklahoma due to increased oil, condensate, natural gas and NGLs production from the full year impact of acquired wells and new wells drilled. Production taxes represented approximately 4% and 5% of oil, condensate, natural gas and NGLs revenues for the years ended December 31, 2014 and 2013, respectively.

Lease operating expenses. We reported lease operating expenses ("LOE") of $19.3 million for the year ended December 31, 2014, up from $9.5 million for the year ended December 31, 2013. Our LOE was $5.21 per Boe for the year ended December 31, 2014, up 78% from $2.92 per Boe for the same period in 2013. This increase in our LOE was primarily due to a $9.7 million increase in our direct controllable LOE and workover expense due to a full year impact of 2013 acquisition wells plus new wells drilled, combined with higher overall costs associated with producing oil versus natural gas and a $403,000 increase in ad valorem taxes. The year ended December 31, 2014 also includes approximately $350,000 of LOE costs associated with pump repair and scale removal. Excluding $185,000 of a one-time reduction to LOE related to an

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arbitration settlement and non-recurring workover expense and other non-recurring costs, our LOE would have been $18.5 million or $5.00 per Boe for the year ended December 31, 2014, compared to $9.2 million or $2.83 per Boe for the same period in 2013. A summary of LOE by area is as follows:

	Lease Operating Expense For the Year Ended December 31, 2014		Lease Operating Expense For the Year Ended December 31, 2013		% Change of $ per Boe	
	(in thousands)	($ per Boe)	(in thousands)	($ per Boe)		
Mid-Continent	$15,112	$9.48	$4,018	$10.17	(7	)%
Appalachian Basin	4,211	$1.99	3,181	$1.33	50	%
East Texas and other	—	$—	2,257	$4.95	(100	)%
Total	$19,323	$5.21	$9,456	$2.92	78	%

The 7% decrease from December 31, 2013 to December 31, 2014 in LOE per Boe for the Mid-Continent is the result of increased production from new wells drilled. The 50% increase from December 31, 2013 to December 31, 2014 in LOE per Boe for the Appalachian Basin was primarily the result of decreased production. The 100% decrease from December 31, 2013 to December 31, 2014 in LOE per Boe for East Texas and other was the result of the sale of our interest in the East Texas properties on October 2, 2013.

Transportation, treating and gathering. We reported transportation expenses of $3.7 million for the year ended December 31, 2014, down from $4.0 million for the year ended December 31, 2013. The year ended December 31, 2014 includes $1.6 million of expense attributed to a one-time adjustment related to an arbitration settlement. Excluding the one-time adjustment, current year transportation expense would have been $2.1 million. The decrease in adjusted transportation expense from December 31, 2013 to December 31, 2014 is primarily due to the elimination of approximately $2.8 million of transportation fees resulting from the sale of our East Texas properties on October 2, 2013 offset by higher transportation and marketing fees in the Appalachian Basin.

Depreciation, depletion and amortization. Depreciation, depletion and amortization (“DD&A”) was $46.2 million for the year ended December 31, 2014, up from $32.4 million for the year ended December 31, 2013. The increase in DD&A expense was the result of a 15% increase in total production volumes attributable to increased Mid-Continent production coupled with a 24% increase in the DD&A rate per Boe. The DD&A rate for the year ended December 31, 2014 was $12.45 per Boe, as compared to $10.02 per Boe for the same period in 2013. The increase in the DD&A rate per Boe is primarily due to full-year impact of 2013 higher cost liquids-focused acquisitions and drilling resulting in an increase in our total liquids production as a percentage of total production for the year ended December 31, 2014 compared to the year ended December 31, 2013. Liquids production represented approximately 48% of total production for the year ended December 31, 2014 compared to 31% of total production for the year ended December 31, 2013. While we did not recognize an impairment charge to oil and natural gas properties in the two years ended December 31, 2014 and 2013, absent significant price increases, the sustained lower oil and natural gas prices experienced in the second half of 2014 and the current year will continue to impact our proved reserves and PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices, which were substantially higher at December 31, 2014 than current oil and natural gas prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn, without significant additions to proved reserves, may make it more likely that we will in the future incur impairment charges against our oil and natural gas properties under full cost accounting.

General and administrative expenses. We reported general and administrative expenses of approximately $16.5 million for the year ended December 31, 2014, down from $17.0 million for the year ended December 31, 2013. Non-cash stock-based compensation expense, which is included in general and administrative expenses, was $4.9 million and $3.4 million for the years ended December 31, 2014 and 2013, respectively. The increase in stock-based compensation expense is due to the granting of additional PBUs to executives and an increase in restricted share grants due to the increase in the number of employees coupled with an increase in the grant fair value for the 2014 grants compared to the 2013 grants due to a higher stock price on the date of grant. Excluding stock-based compensation expense, general and administrative expense decreased $1.9 million to $11.6 million for the year ended December 31, 2014 compared to $13.5 million for the year ended December 31, 2013. The $1.9 million decrease from 2013 to 2014 is primarily due to a decrease in acquisition costs of $2.3 million, lower costs associated with the migration of Parent from Canada to the U.S. of $950,000 and $659,000 of severance cost in 2013 related to property divestments. Excluding these non-recurring costs, general and administrative expenses increased $2.0 million from 2013 to 2014 due to higher legal costs including $880,000 related to the Eagle Natrium LLC litigation and higher personnel and facilities costs related to staff increases to support current operations and the 2013 property acquisitions.

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 no litigation settlement expense in 2014.

Gain on acquisition of assets at fair value. We reported a bargain purchase gain of $27.7 million, net of income tax expense of $16.0 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, net of income tax. 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 $27.6 million for the year ended December 31, 2014 compared to $13.2 million for the year ended December 31, 2013. Interest expense excludes $4.3 million and $3.3 million of capitalized interest in 2014 and 2013, respectively, which related to capital expenditures for undeveloped projects in the Appalachian Basin and the Mid-Continent. Excluding capitalized interest, interest expense increased $15.4 million from December 31, 2013 to December 31, 2014 due to higher outstanding debt balances at higher interest rates throughout the year ended December 31, 2014 directly resulting from the issuance in May and November of 2013 $200.0 million and $125.0 million, respectively, of our 8 5/8% Senior Secured Notes due 2018 issued during the year.

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 $14.4 million for the year ended December 31, 2014 compared to $9.4 million for the year ended December 31, 2013. The Series A Preferred Stock had a stated value of approximately $78.8 million and $76.8 million at December 31, 2014 and 2013, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $8.7 million and $8.5 million for the years ended December 31, 2014 and 2013, respectively. The increase in dividends on Series A Preferred Stock is due to the issuance of 86,840 preferred shares during the year ended December 31, 2014. The Series B Preferred Stock, issued during November 2013, had a stated value of approximately $50.0 million at December 31, 2014 and 2013 and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $5.8 million and $847,000 for the years ended December 31, 2014 and 2013, respectively. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at December 31, 2014, our future stated preferred dividend expense is approximately $3.6 million per quarter, which is subject to being declared and paid monthly.

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 8.9 MBoe/d for the year ended December 31, 2013 compared to 6.0 MBoe/d for the same period in 2012. During 2013, production in the Marcellus Shale averaged 6.5 MBoe/d compared to 2012 production of 3.7 MBoe/d, a 78% increase. For the year ended December 31, 2013, production in the Mid-Continent averaged 1.1 MBoe/d compared to 2012 production of 0.01 MBoe/d. During 2013, production in East Texas averaged 1.2 MBoe/d compared to 2012 production of 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 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.

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 designated a portion of our crude hedges as price protection for our NGLs production.

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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 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 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 was 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 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 $2.92 per Boe for the year ended December 31, 2013, up 4% from $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 $2.83 per Boe for the year ended December 31, 2013, compared to $5.4 million or $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 Boe)	(in thousands)	($ per Boe)		
Mid-Continent	$4,018	$10.17	$33	$18.79	(46	)%
Appalachia	3,181	$1.33	2,071	$1.54	(13	)%
East Texas	2,253	$4.97	3,624	$4.35	14	%
Other	4	$1.57	446	$15.43	(90	)%
Total	$9,456	$2.92	$6,174	$2.80	4	%

The 46% decrease from December 31, 2012 to December 31, 2013 in LOE per 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 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 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 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 resulted from actual production volumes being less than minimum contractual volume requirements. The purchaser of our East Texas properties assumed any future minimum volume requirement obligations.

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 Boe. The DD&A rate for the year ended December 31, 2013 was $10.02 per Boe, as compared to $11.52 per Boe for the same period in 2012. The decrease in the DD&A rate per Boe was 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.

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.

Gain on acquisition of assets at fair value. We reported a bargain purchase gain of $27.7 million, net of income tax expense of $16.0 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, net of income tax. 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.

Liquidity and Capital Resources

Overview. Our primary sources of liquidity and capital resources are internally generated cash flows from operating activities, availability under the Revolving Credit Facility, access to capital markets, to the extent available and asset sales. We believe that the funds from operating cash flows, available borrowings under our Revolving Credit Facility and proceeds from capital markets transactions should be sufficient to meet our cash requirements for at least the next 12 months. 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 oil, condensate, natural gas and NGLs prices, drilling results and cash flow.

For the year ended December 31, 2014, we reported cash flows provided by operating activities of $64.3 million. For the year ended December 31, 2014, we reported net cash used in investing activities of $214.7 million, primarily for the development and purchase of oil and natural gas properties. For the year ended December 31, 2014, we reported net cash provided by financing activities of $129.0 million, consisting primarily of $101.3 million of net proceeds from the issuance of common stock, $45.0 million of net borrowings under the Revolving Credit Facility and $2.1 million of net proceeds from the issuance of Series A Preferred Stock partially offset by $14.4 million of dividends paid on the preferred stock and $4.6 million of tax withholding payments related to restricted stock and PBU vestings during the period. As a result of these activities, our cash and cash equivalents balance decreased by $21.4 million, resulting in a December 31, 2014 balance of cash and cash equivalents of $11.0 million. Net cash provided by operating activities increased $16.5 million from 2013 primarily due to increased oil, condensate, natural gas and NGLs revenues in 2014 resulting from a 43% increase in weighted average realized prices and a 15% increase in production. Cash flow used in investing activities decreased $50.8 million from 2013 to 2014 primarily due to there not being any large oil and natural gas acquisitions during 2014 partially offset by an increase in capital expenditures to develop and purchase oil and natural gas properties.

At December 31, 2014, we had a net working capital surplus of approximately $8.6 million, including $1.8 million of advances from non-operators. At December 31, 2014, availability under the Revolving Credit Facility was $100.0 million.

Future capital and other expenditure requirements. Capital expenditures for 2015 are projected to be approximately $102.5 million. In the Appalachian Basin and Mid-Continent area, we expect to spend $27.0 million and $69.0 million, respectively, for drilling, completion, infrastructure, lease acquisition and seismic costs. The planned 2015 capital expenditures are expected to provide for spudding a total of 14 gross (12.2 net) wells and completing 21 gross (16.2 net) wells in the Hunton Limestone play, completing seven gross (3.5 net) wells in the Marcellus Shale play and completing one gross (0.5 net) well in the Utica Shale. In addition, we have allocated $6.5 million for capitalized interest and other costs. We plan to fund our 2015 capital budget through existing cash balances, internally generated cash flow from operating activities, borrowings under the Revolving Credit Facility and possible divestiture of assets 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 94% of our budgeted 2015 capital expenditures, and thus, we could reduce a significant portion of 2015 capital expenditures if necessary to better match available capital resources. For more information, 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 oil hedges as price protection for a portion of our NGLs production.

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As of December 31, 2014, 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 (in MMBtu's)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
2015(1)	Protective spread	10,000	900,000	$4.46	$—	$3.70	$—
2015(1)	Call spread	10,000	900,000	$—	$—	$—	$5.00
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(1)	Producer three-way collar	3,750	337,500	$—	$4.60	$3.50	$5.34
2015(1)	Producer three-way collar	2,500	337,500	$—	$4.40	$3.65	$5.00
2015	Producer three-way collar	2,000	760,000	$—	$4.00	$3.25	$4.58
2015	Basis swap(2)	2,500	912,500	$(1.12)	$—	$—	$—
2015	Basis swap(2)	2,500	912,500	$(1.11)	$—	$—	$—
2015	Basis swap(2)	2,500	912,500	$(1.14)	$—	$—	$—
2015(3)	Protective spread	5,000	1,375,000	$4.00	$—	$3.25	$—
2015(3)	Producer three-way collar	2,500	687,500	$—	$3.70	$3.00	$4.09
2015(3)	Producer three-way collar	5,000	1,375,000	$—	$3.77	$3.00	$4.11
2016	Protective spread	2,000	732,000	$4.11	$—	$3.25	$—
2016	Producer three-way collar	2,000	732,000	$—	$4.00	$3.25	$4.58

(1) For the period January to March 2015.
(2) Represents basis swaps at the sales point of Dominion South.
(3) For the period April to December 2015.

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As of December 31, 2014, 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)
2015(2)	Costless collar	400	72,400	$—	$85.00	$—	$96.50
2015(2)	Costless collar	366	66,300	$—	$85.00	$—	$97.80
2015(2)	Costless collar	150	27,150	$—	$85.00	$—	$96.25
2015(3)	Costless three-way collar	400	73,600	$—	$85.00	$70.00	$96.50
2015(3)	Costless three-way collar	325	59,800	$—	$85.00	$65.00	$97.80
2015(3)	Costless three-way collar	50	9,200	$—	$85.00	$65.00	$96.25
2015(2)	Put spread	700	126,700	$—	$90.00	$70.00	$—
2015	Put spread	250	91,250	$—	$89.00	$69.00	$—
2015(3)	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(4)	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 2015.
(3) For the period July to December 2015.
(4) For the period January to August 2018.

As of December 31, 2014, the following NGLs derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume (in Bbls)	Total of Notional Volume	Base Fixed Price
2015(1)	Fixed price swap	250	68,750	$45.61

(1) For the period April to December 2015.

For more information, see Item 8. "Financial Statements and Supplementary Data, Note 7. Derivative Instruments and Hedging Activity" included in this Form 10-K.
At December 31, 2014, the estimated fair value of all of our commodity derivative instruments was a net asset of $27.5 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, 2014, we had a current commodity derivative premium payable of $2.5 million and a long-term commodity derivative premium payable of $4.7 million. The put premium liabilities are payable monthly as the hedge production month becomes the prompt production month.

By removing the price volatility from a portion of our oil, condensate and natural gas sales for 2015 to 2018, we believe that we have mitigated, but not eliminated, the potential effects of changing prices on a portion of our operating cash flow for

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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, 2014, 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 the majority of our open derivatives at December 31, 2014 is provided under the Revolving Credit Facility through intercreditor agreements. Although we are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above, we do not anticipate non-performance by such counterparties.
Revolving Credit Facility. Our Revolving Credit Facility provides for a maximum amount of $500.0 million, subject to a borrowing base, which, at December 31, 2014, was $145.0 million. At December 31, 2014, we had $45.0 million of borrowings outstanding under our Revolving Credit Facility compared to our December 31, 2013 Revolving Credit Facility balance of zero. Effective March 9, 2015, the borrowing base under the Revolving Credit Facility was increased by the lenders to $200.0 million. Borrowing base re-determinations are scheduled semi-annually with the next regularly scheduled re-determination scheduled for November 2015. However, we and the lenders may each request one additional unscheduled redetermination during any six-month period between scheduled re-determinations. 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) LIBOR plus 1%. 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 and subject to adjustments based on the Company's leverage ratio. Under the Revolving Credit Facility, we are subject to certain financial covenants, including a senior secured leverage ratio, an interest coverage ratio, a total leverage ratio and a current ratio requirement, as adjusted.
At December 31, 2014, 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. We have $325.0 million of senior secured notes outstanding, which are due May 15, 2018. For a more detailed description of the terms of our Notes, see Item 8. "Financial Statements and Supplementary Data, Note 4. Long-Term Debt - Senior Secured Notes" included in this Form 10-K. At December 31, 2014, we were in compliance with all covenants under the indenture governing the Notes.
Series A Preferred Stock. For the year ended December 31, 2014, we sold 86,840 shares of Series A Preferred Stock under our ATM Agreement for net proceeds of $2.1 million. We 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, 2014, 2013 and 2012, we recognized dividend expense of $8.7 million, $8.5 million and $7.1 million, respectively, for the Series A Preferred Stock.
Series B Preferred Stock. On November 7, 2013, we issued 2,140,000 shares of 10.75% Series B Preferred Stock at $25.00 per share. We 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 years ended December 31, 2014 and 2013, we recognized dividend expense of $5.7 million and $847,000, respectively, for the Series B Preferred Stock.

Off-Balance Sheet Arrangements
As of December 31, 2014, 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, 2014:

	Payments Due by Period						
	Total	2015	2016	2017	2018	2019	Thereafter
	(in thousands)						
Long-term debt[1]	$370,000	$—	$—	$45,000	$325,000	$—	$—
Interest on long-term debt[2]	97,732	29,120	29,120	28,980	10,512	—	—
Deferred put premiums[3]	7,183	2,481	2,408	1,460	834	—	—
Office space leases[4]	1,464	631	490	182	161	—	—
Office equipment leases	22	9	8	5	—	—	—
Drilling rigs	434	434	—	—	—	—	—
Total contractual obligations	$476,835	$32,675	$32,026	$75,627	$336,507	$—	$—

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(1) For a discussion of the Revolving Credit Facility and the Notes, see Item 8. “Financial Statements and Supplementary Data, Note 4. Long-Term Debt” included in this Form 10-K.

(2) Interest payments have been calculated by applying the weighted average interest rate of 8.625% at December 31, 2014 to the outstanding Notes balance of $325.0 million at December 31, 2014 and by applying the weighted average interest rate of 2.42% at December 31, 2014 to the outstanding Revolving Credit Facility balance of $45.0 million at December 31, 2014.

(3) In conjunction with certain crude commodity derivatives contracts, we deferred the payment of certain put premiums for the period January 2015 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, 2018 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, 2014, our reserve for these obligations totaled $5.6 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” included in this Form 10-K.

We have employment agreements with our Chief Executive Officer, Chief Financial Officer and Chief Operating 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. During June 2014, we entered into an agreement to include the dedication of all of our Wetzel County, West Virginia production to SEI in addition to our Marshall County, West Virginia production. All natural gas is transported and processed at either William's 520.0 MMcf/d Fort Beeler processing plant or William's 200.0 MMcf/d Oak Grove 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 nine 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

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which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided an expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate or policy to be critical if:

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

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

Full Cost Method of Accounting

We follow the full cost method of accounting for 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 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 and natural gas 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 oil and natural gas properties is not reversible at a later date even if oil and natural gas 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 oil and natural gas properties and as additional depletion. 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.

In 2014, the key benchmark base prices utilized were the Henry Hub price of $4.35 per MMBtu for natural gas and a WTI spot price of $94.99 per barrel of oil. In applying the full cost method at December 31, 2014 and 2013, 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

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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, 2014 and 2013. 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 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. 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, 2014 would have reduced our ceiling impairment cushion by approximately $131.3 million resulting in no impairment. A 10% increase in prices at December 31, 2014 would have increased our ceiling impairment cushion by approximately $127.2 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 oil and natural gas that are ultimately recovered.

In addition, economic producibility of reserves is dependent on the oil and natural gas prices used in the reserves estimate. We based our December 31, 2014 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, 2014 by approximately $1.1 million, while a 10% decrease in reserves would have increased our depletion expense by approximately $1.3 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 oil and natural gas property costs to be amortized.

At December 31, 2014, we had $128.3 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 $9.8 million, respectively, for the year ended December 31, 2014.

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 capitalize interest on the Notes and the Revolving Credit Facility. The interest to be capitalized for any period is derived by multiplying the average rate of interest times the average qualifying assets during the period. To qualify for interest capitalization, we must continue to make progress on the development of the assets. Capitalized interest was approximately \$4.3 million, \$3.3 million and \$1.9 million for 2014, 2013 and 2012, 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, 2014.

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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.

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:

Revenue Recognition. In May 2014, the FASB issued an amendment to previously issued guidance regarding the recognition of revenue. The FASB and the International Accounting Standards Board initiated a joint project to clarify the principles for recognizing revenue and to develop a common standard that would (i) remove inconsistencies and weaknesses in revenue requirements, (ii) provide a more robust framework for addressing revenue issues, (iii) improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets, (iv) provide more useful information to users of financial statements through improved disclosure requirements and (v) simplify the preparation of financial statements by reducing the number of requirements to which an entity must refer. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, an entity should apply the following steps (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This guidance supersedes prior revenue recognition requirements and most industry-specific guidance throughout the Codification. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The Company is still considering the method of adoption but does not expect the adoption of this guidance to materially impact its operating results, financial position or cash flows.

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. The adoption of this guidance did not impact the Company's operating results, financial position or cash flows.

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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, 2014, 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, 2014, a 10% change in the prices received for our oil, condensate, natural gas and NGLs production would have had an approximate $15.2 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. For more information regarding our hedging activities, see Item 8. “Financial Statements and Supplementary Data, Note 7. Derivative Instruments and Hedging Activity” included in this Form 10-K.

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, 2014, we had $45.0 million of 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.

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Item 8. Financial Statements and Supplementary Data

GASTAR EXPLORATION INC. AND SUBSIDIARIES
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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, 2014 and 2013 and the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2014. 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, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 12, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
March 12, 2015

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GASTAR EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	2013
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,008	$32,393
Accounts receivable, net of allowance for doubtful accounts of $0 and $507, respectively	30,841	21,656
Commodity derivative contracts	19,687	—
Prepaid expenses	2,083	1,145
Total current assets	63,619	55,194
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	128,274	96,220
Proved properties	1,124,367	935,773
Total natural gas and oil properties	1,252,641	1,031,993
Furniture and equipment	3,010	2,691
Total property, plant and equipment	1,255,651	1,034,684
Accumulated depreciation, depletion and amortization	(563,351)	(517,171)
Total property, plant and equipment, net	692,300	517,513
OTHER ASSETS:		
Commodity derivative contracts	7,815	7,545
Deferred charges, net	2,586	2,950
Advances to operators and other assets	9,474	6,733
Total other assets	19,875	17,228
TOTAL ASSETS	$775,794	$589,935
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$28,843	$11,046
Revenue payable	9,122	12,514
Accrued interest	3,528	3,504
Accrued drilling and operating costs	5,977	8,756
Advances from non-operators	1,820	9,259
Commodity derivative contracts	—	3,403
Commodity derivative premium payable	2,481	145
Asset retirement obligation	82	633
Other accrued liabilities	3,175	4,844
Total current liabilities	55,028	54,104
LONG-TERM LIABILITIES:		
Long-term debt	360,303	312,994
Commodity derivative contracts	—	378
Commodity derivative premium payable	4,702	7,000
Asset retirement obligation	5,475	5,430
Total long-term liabilities	370,480	325,802
Commitments and contingencies (Note 14)		
STOCKHOLDERS' EQUITY:		

Preferred stock, 40,000,000 shares authorized		
Series A Preferred stock, par value $0.01 per share; 10,000,000 shares authorized; 4,045,000 and 3,958,160 shares issued and outstanding at December 31, 2014 and 2013, respectively, with liquidation preference of $25.00 per share	41	40
Series B Preferred stock, par value $0.01 per share; 10,000,000 shares authorized; 2,140,000 shares issued and outstanding at December 31, 2014 and 2013, respectively, with liquidation preference of $25.00 per share	21	21
Common stock, par value $0.001 per share; 275,000,000 shares authorized; 78,632,810 and 61,211,658 shares issued and outstanding at December 31, 2014 and 2013, respectively	78	61
Additional paid-in capital	568,440	464,730
Accumulated deficit	(218,294)	(254,823)
Total stockholders' equity	350,286	210,029
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$775,794	$589,935

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,		
	2014	2013	2012
	(in thousands, except share and per share data)		
REVENUES:			
Oil and condensate	$82,820	$36,480	$11,570
Natural gas	47,647	40,416	23,318
NGLs	21,382	15,611	7,630
Total oil and condensate, natural gas and NGLs revenues	151,849	92,507	42,518
Gain (loss) on commodity derivatives contracts	19,569	(4,752)	7,422
Total revenues	171,418	87,755	49,940
EXPENSES:			
Production taxes	6,733	4,651	2,269
Lease operating expenses	19,323	9,456	6,174
Transportation, treating and gathering	3,679	4,006	4,965
Depreciation, depletion and amortization	46,180	32,449	25,424
Impairment of natural gas and oil properties	—	—	150,787
Accretion of asset retirement obligation	506	468	388
General and administrative expense	16,485	16,961	12,211
Litigation settlement expense	—	1,000	1,250
Total expenses	92,906	68,991	203,468
INCOME (LOSS) FROM OPERATIONS	78,512	18,764	(153,528)
OTHER INCOME (EXPENSE):			
Gain on acquisition of assets at fair value, net of income taxes	—	27,670	—
Interest expense	(27,571)	(13,168)	(270)
Investment and other income	19	48	9
Foreign transaction loss	(7)	(14)	(2)
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES	50,953	33,300	(153,791)
Income tax benefit	—	(16,042)	—
NET INCOME (LOSS)	50,953	49,342	(153,791)
Dividends on preferred stock	(14,424)	(9,378)	(7,077)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$36,529	$39,964	$(160,868)
NET INCOME (LOSS) PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:			
Basic	$0.58	$0.66	$(2.53)
Diluted	$0.55	$0.63	$(2.53)
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:			
Basic	63,270,733	60,220,115	63,538,362
Diluted	66,492,589	63,618,401	63,538,362

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

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Equity
	Shares	Amount	Shares	Amount	Shares	Amount			
	(in thousands, except share data)								
Balance at December 31, 2011	1,364,543	$14	—	$—	64,706,750	$316,346	$52,753	$(133,919)	$235,194
Issuance of preferred stock	2,586,711	26	—	—	—	—	49,224	—	49,250
Issuance of restricted stock	—	—	—	—	1,916,980	—	—	—	—
Forfeitures of restricted stock	—	—	—	—	(191,728)	—	(335)	—	(335)
Exercise of stock options, net of forfeitures	—	—	—	—	607	—	—	—	—
Stock based compensation	—	—	—	—	—	—	3,295	—	3,295
Preferred stock dividends	—	—	—	—	—	—	—	(7,077)	(7,077)
Net loss	—	—	—	—	—	—	—	(153,791)	(153,791)
Balance at December 31, 2012	3,951,254	$40	—	$—	66,432,609	$316,346	$104,937	$(294,787)	$126,536
Issuance of preferred stock	6,906	—	2,140,000	21	—	—	50,160	—	50,181
Repurchase of shares of common stock	—	—	—	—	(6,781,768)	(9,753)	—	—	(9,753)
Reclassification of par value of common stock	—	—	—	—	—	(306,532)	306,532	—	—
Issuance of restricted stock	—	—	—	—	2,288,179	—	—	—	—
Forfeitures of restricted stock	—	—	—	—	(737,362)	—	(334)	—	(334)
Exercise of stock options, net of forfeitures	—	—	—	—	10,000	—	—	—	—
Stock based compensation	—	—	—	—	—	—	3,435	—	3,435
Preferred stock dividends	—	—	—	—	—	—	—	(9,378)	(9,378)
Net income	—	—	—	—	—	—	—	49,342	49,342
	3,958,160	$40	2,140,000	$21	61,211,658	$61	$464,730	$(254,823)	$210,029

Balance at December 31, 2013									
Issuance of preferred stock	86,840	1	—	—	—	—	2,065	—	2,066
Issuance of shares - cash, net of offering costs of $4,931	—	—	—	—	17,000,000	17	101,302	—	101,319
Issuance of shares - performance based units vesting, net of forfeitures	—	—	—	—	472,189	—	—	—	—
Issuance of restricted stock	—	—	—	—	601,473	—	—	—	—
Forfeitures of restricted stock	—	—	—	—	(659,227)	—	(4,562)	—	(4,562)
Exercise of stock options, net of forfeitures	—	—	—	—	6,717	—	15	—	15
Stock based compensation	—	—	—	—	—	—	4,890	—	4,890
Preferred stock dividends	—	—	—	—	—	—	—	(14,424)	(14,424)
Net income	—	—	—	—	—	—	—	50,953	50,953
Balance at December 31, 2014	4,045,000	$41	2,140,000	$21	78,632,810	$78	$568,440	$(218,294)	$350,286

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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,		
	2014	2013	2012
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$50,953	$49,342	$(153,791)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	46,180	32,449	25,424
Impairment of natural gas and oil properties	—	—	150,787
Stock-based compensation	4,890	3,435	3,295
Mark to market of commodity derivatives contracts:			
Total (gain) loss on commodity derivatives contracts	(19,569)	4,752	(7,422)
Cash settlements of matured commodity derivative contracts, net	(4,901)	5,892	16,251
Cash premiums paid for commodity derivatives contracts	(185)	(152)	(4,539)
Amortization of deferred financing costs	3,067	2,322	224
Accretion of asset retirement obligation	506	468	388
Settlement of asset retirement obligation	(588)	(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	(12,524)	(8,431)	2,487
Prepaid expenses	(938)	(48)	146
Accounts payable and accrued liabilities	(2,566)	1,563	4,441
Net cash provided by operating activities	64,325	47,814	37,055
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development and purchase of oil and natural gas properties	(155,631)	(95,343)	(136,311)
Advances to operators	(61,067)	(22,213)	(9,649)
Acquisition of oil and natural gas properties - refund (expenditure)	4,209	(251,096)	—
Proceeds from sale of oil and natural gas properties	5,530	112,201	—
Use of proceeds from non-operators	(7,439)	(8,281)	(1,983)
Purchase of furniture and equipment	(319)	(766)	(296)
Net cash used in investing activities	(214,717)	(265,498)	(148,239)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of common shares, net of issuance costs	101,319	—	—
Repurchase of common stock	—	(9,753)	—
Proceeds from revolving credit facility	103,000	19,000	98,000
Repayment of revolving credit facility	(58,000)	(117,000)	(30,000)
Proceeds from issuance of senior secured notes, net of discount	—	312,279	—
Proceeds from issuance of preferred stock, net of issuance costs	2,064	50,183	49,250
Dividends on preferred stock	(14,424)	(9,378)	(7,077)
Deferred financing charges	(405)	(3,785)	(450)
Tax withholding related to restricted stock and PBU vestings	(4,562)	(334)	(336)
Other	15	(36)	51
Net cash provided by financing activities	129,007	241,176	109,438
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(21,385)	23,492	(1,746)

CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	32,393	8,901	10,647
CASH AND CASH EQUIVALENTS, END OF PERIOD	$11,008	$32,393	$8,901

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

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GASTAR EXPLORATION INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Gastar Exploration Inc. ("Gastar") is an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Gastar'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. In Oklahoma, Gastar is developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and expects to test other prospective formations on the same acreage, including the Woodford Shale and the Meramec Shale (middle Mississippi Lime), which Gastar refers to as the Stack Play. In West Virginia, Gastar is developing liquids-rich natural gas in the Marcellus Shale and has drilled its first successful dry gas Utica Shale/Point Pleasant well on its acreage. Gastar completed the sale of 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 Gastar Exploration, Inc.'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." Gastar Exploration Inc., together with its subsidiary, owns and continues to conduct business in substantially the same manner as was being conducted by Gastar Exploration, Inc. and its subsidiaries prior to the merger. All references to "Gastar," the "Company" and similar terms refer collectively to Gastar Exploration Inc. 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.).

2. Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements of the Company are stated in U.S. dollars unless otherwise noted and have been prepared by management in accordance with 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 oil and natural gas 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 oil and natural gas reserve quantities and the related present value of estimated future net cash flows. See Note 18. "Supplemental Oil and Gas Disclosures."

All prior year balances are those of Gastar Exploration, Inc.

Reclassifications

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

Subsequent Events

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

Principles of Consolidation

The consolidated financial statements of the Company include the consolidated accounts of all its subsidiaries. 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

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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 $11.0 million and $32.4 million as of December 31, 2014 and 2013, 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,		
	2014	2013	2012
	(in thousands)		
Allowance for doubtful accounts, beginning of year	$507	$546	$551
Expense	—	—	—
Reductions/write-offs	(507)	(39)	(5)
Allowance for doubtful accounts, end of year	$—	$507	$546

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, 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, 2014 and 2013 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.

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 Notes and Revolving Credit Facility were included in the rate calculation of capitalized interest incurred for the year-ended December 31, 2014. 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 $4.3 million, $3.3 million and $1.9 million for 2014, 2013 and 2012, 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.

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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,	
	2014	2013
Deferred charges	$3,664	$3,269
Accumulated amortization	(1,078)	(319)
Deferred charges, net	$2,586	$2,950

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 2014, 2013 or 2012.

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, 2014 and 2013.

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

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.

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Industry Segment and Geographic Information
The Company operates in one industry segment, which is the exploration, development and production of oil and natural gas. 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. The Company owns immaterial non-operating working interests in two natural gas wells located in Alberta, Canada, from which it has received no revenue since January 1, 2012.
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:
Revenue Recognition. In May 2014, the FASB issued an amendment to previously issued guidance regarding the recognition of revenue. The FASB and the International Accounting Standards Board initiated a joint project to clarify the principles for recognizing revenue and to develop a common standard that would (i) remove inconsistencies and weaknesses in revenue requirements, (ii) provide a more robust framework for addressing revenue issues, (iii) improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets, (iv) provide more useful information to users of financial statements through improved disclosure requirements and (v) simplify the preparation of financial statements by reducing the number of requirements to which an entity must refer. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, an entity should apply the following steps (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This guidance supersedes prior revenue recognition requirements and most industry-specific guidance throughout the FASB Accounting Standards Codification. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The Company does not expect the adoption of this guidance to materially impact its operating results, financial position or cash flows.
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. The adoption of this guidance did not impact the Company's operating results, financial position or cash flows.

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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 and Texas. 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 total property, plant and equipment consists of the following:

	December 31, 2014	2013
	(in thousands)	
Oil and natural gas properties, full cost method of accounting:		
Unproved properties	$128,274	$96,220
Proved properties	1,124,367	935,773
Total oil and natural gas properties	1,252,641	1,031,993
Furniture and equipment	3,010	2,691
Total property and equipment	1,255,651	1,034,684
Impairment of proved natural gas and oil properties	(337,939)	(337,939)
Accumulated depreciation, depletion and amortization	(225,412)	(179,232)
Total accumulated depreciation, depletion and amortization	(563,351)	(517,171)
Total property and equipment, net	$692,300	$517,513

Included in the Company's oil and natural gas properties are asset retirement costs of $2.4 million and $3.4 million as of December 31, 2014 and 2013, respectively.

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

	December 31, 2014	2013
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$29,193	$4,774
Acreage acquisition costs	91,362	86,097
Capitalized interest	7,719	5,349
Total unproved properties excluded from amortization	$128,274	$96,220

For the years ended December 31, 2014 and 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 $3.3 million and $20.5 million of unproved properties to proved properties for the years ended December 31, 2014 and 2013, respectively.

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 oil and natural gas properties is not reversible at a later date even if oil and natural gas prices increase. The ceiling calculation dictates that the trailing 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect are held constant indefinitely. The 12-month unweighted arithmetic average of the first-day-of-the-month prices are adjusted for basis and quality differentials in determining the present value of the reserves. The table below sets forth relevant assumptions utilized in the quarterly ceiling test computations for the respective periods noted:

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2014	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)[1]		$4.35	$4.24	$4.10	$3.99
West Texas Intermediate oil price (per Bbl)[1]		$94.99	$99.08	$100.11	$98.30
Impairment recorded (pre-tax) (in thousands)	$—	$—	$—	$—	$—

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	$—

(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 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.

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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, net of $16.0 million of income tax expense, was recognized in the accompanying consolidated statements of operations for the year ended December 31, 2013. 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, 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.

WEHLU Acquisition

On September 4, 2013, Gastar USA entered into a Purchase and Sale Agreement, dated September 4, 2013, by and among 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 Agreement, Gastar USA completed the acquisition of the WEHLU Assets on November 15, 2013 for an adjusted cash purchase price of $177.8 million, (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 Unaudited 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)

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

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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 adjusted net proceeds of approximately $42.9 million. 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 60 horizontal wells by year-end 2013. Due to natural gas price declines, Atinum and Gastar USA agreed to reduce the minimum wells to be drilled requirements from the originally agreed upon 60 wells to 51 wells. At December 31, 2014, 67 gross (32.0 net) operated Marcellus Shale wells and one gross (0.5 net) gross operated Utica Shale well were capable of production under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015.

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

On June 7, 2013, the Company entered into the Second Amended and Restated Credit Agreement among the Company, 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”). At the Company's election, borrowings bear interest 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 (ii) the federal funds rate plus 50 basis points or (iii) LIBOR plus 1.0%. 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 and subject to adjustments based on the Company's leverage ratio. An annual commitment fee of 0.5% is payable quarterly on the unutilized balance of the borrowing base. The Revolving Credit Facility has a scheduled maturity of November 14, 2017.

The Revolving Credit Facility will be guaranteed by all of the Company's 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 the Company and its subsidiaries, excluding de minimis 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 the Company.

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, subject to the modifications in Amendment No. 5 set forth below; 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, subject to the modifications in Amendment No. 5 set forth below.

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 the Company, as defined in the Revolving Credit Facility.

On March 9, 2015, the Company, together with the parties thereto, entered into a Master Assignment, Agreement and Amendment No. 5 (“Amendment No. 5”) to Second Amended and Restated Credit Agreement. Amendment No. 5 amended the Revolving Credit Facility to, among other things, (i) increase the borrowing base from $145.0 million to $200.0 million, (ii) adjust the leverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to September 30, 2016, to 5.25 to 1.00; for the fiscal quarter ending on September 30, 2016, to 5.00 to 1.00; for the fiscal quarter ending on December 31, 2016, to 4.75 to 1.00; for the fiscal quarter ending on March 31, 2017, to 4.25 to 1.00; and for each fiscal quarter ending on or after June 30, 2017, to 4.00 to 1.00, (iii) adjust the interest coverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to March 31, 2016, to 2.00 to 1.00 and for each fiscal quarter ending on or after March 31, 2016, to 2.50 to 1.00, and (iv) add the senior secured leverage ratio covenant, such ratio not to exceed, (a) for each fiscal quarter ending on or after March 31, 2015 but prior to June 30, 2016, 2.25 to 1.00 and (b) for each fiscal quarter ending on or after June 30, 2016, 2.00 to 1.00 provided that this senior secured leverage ratio shall cease to apply commencing with the first fiscal quarter end occurring after June 30, 2016 for which the total leverage ratio is equal to or less than 4.00 to 1.00.

Borrowing base re-determinations are scheduled semi-annually in May and November of each calendar year. The Company and its lenders may each request one additional unscheduled re-determination during any six-month period between scheduled re-determinations. At December 31, 2014, the Revolving Credit Facility had a borrowing base of $145.0 million, with $45.0 million of borrowings outstanding and availability of $100.0 million. Effective March 9, 2015, the borrowing base was increased to $200.0 million. The next regularly scheduled re-determination is set for November 2015. 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”).

At December 31, 2014, the Company was in compliance with all financial covenants under the Revolving Credit Facility.

Senior Secured Notes

The Company has \$325.0 million aggregate principal amount of 8 5/8% Senior Secured Notes due May 15, 2018 (the "Notes") outstanding under an indenture (the "Indenture") by and among the Company, 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"). 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.

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In the event of a change of control, as defined in the Indenture, each holder of the Notes will have the right to require the Company 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.

The Notes will be guaranteed, jointly and severally, on a senior secured basis by certain future domestic subsidiaries (the “Guarantees”). The Notes and Guarantees will rank senior in right of payment to all of the Company's and the Guarantors' future subordinated indebtedness and equal in right of payment to all of the Company's and the Guarantors' existing and future senior indebtedness. The Notes and Guarantees also will be effectively senior to the Company's unsecured indebtedness and effectively subordinated to the Company'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 the Company'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 the Company's assets;
- Incur dividend or other payment restrictions affecting future restricted subsidiaries;
- Merge, consolidated or transfer all or substantially all of the Company'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, the Company 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, the Company 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. The Company 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. Pursuant to the Registration Rights Agreements entered into in connection with the offering and sale of the Notes, in May 2014, holders of the Notes exchanged their notes for registered notes with the same terms.

At December 31, 2014, the Notes reflected a balance of $315.3 million, net of unamortized discounts of $9.7 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,		
	2014	2013	2012
	(in thousands)		
Asset retirement obligation, beginning of year	$6,063	$6,963	$8,275
Liabilities incurred during period	305	3,416	271
Liabilities settled during period	(704)	(126)	(297)
Accretion expense	506	468	388
Revision in previous estimates and other	32	60	553
Deletions related to property disposals	(645)	(4,718)	(2,227)
Asset retirement obligation, end of year	$5,557	$6,063	$6,963

As of December 31, 2014, the current portion of the Company's asset retirement obligation was $82,000 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, 2014 and 2013, 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, the Company reclassified $3.3 million and $20.5 million of unproved properties to proved properties for the years ended December 31, 2014 and 2013, respectively. As no other fair value measurements are required to be recognized on a non-recurring basis at December 31, 2014, no additional disclosures are provided at December 31, 2014.

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 oil, natural gas and NGLs price risk. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs. The fair values derived from counterparties and third-party brokers are verified by the Company using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its

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commodity derivative instruments, the Company does not have access to the specific assumptions used in its counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided and the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments.

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

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the 2014 and 2013 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, 2014 and 2013:

	Fair value as of December 31, 2014			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$11,008	$—	$—	$11,008
Commodity derivative contracts	—	—	27,502	27,502
Liabilities:				
Commodity derivative contracts	—	—	—	—
Total	$11,008	$—	$27,502	$38,510

	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
Restricted cash	—	—	—	—
Commodity derivative contracts	—	—	7,545	7,545
Liabilities:				
Commodity derivative contracts	—	—	(3,781)	(3,781)
Total	$32,393	$—	$3,764	$36,157

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, 2014 and 2013. 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, 2014 and 2013.

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	For the years ended December 31,	
	2014	2013
	(in thousands)	
Balance at beginning of period	$3,764	$6,465
Total gains (losses) included in earnings	19,569	(4,752)
Purchases	369	9,772
Issuances	—	(2,308)
Settlements[(1)]	3,800	(5,413)
Balance at end of period	$27,502	$3,764
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, 2014 and 2013	$23,902	$(9,967)

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

At December 31, 2014, 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, 2014 was $330.6 million based on quoted market prices of the Notes (Level 1) and the respective carrying value of the Revolving Credit Facility because the interest rate approximated the current market rate (Level 2). 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 Notes (Level 1).

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, 2014, the Company reported a gain of $23.9 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, 2013 and 2012, the Company reported losses of $10.0 million and $5.6 million, respectively, in the consolidated statement of operations related to the change in the fair value of its commodity derivative instruments.

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As of December 31, 2014, 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)					
2015(1)	Protective spread	10,000	900,000	$4.46	$—	$3.70	$—
2015(1)	Call spread	10,000	900,000	$—	$—	$—	$5.00
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(1)	Producer three-way collar	3,750	337,500	$—	$4.60	$3.50	$5.34
2015(1)	Producer three-way collar	2,500	337,500	$—	$4.40	$3.65	$5.00
2015	Producer three-way collar	2,000	760,000	$—	$4.00	$3.25	$4.58
2015	Basis swap(2)	2,500	912,500	$(1.12)	$—	$—	$—
2015	Basis swap(2)	2,500	912,500	$(1.11)	$—	$—	$—
2015	Basis swap(2)	2,500	912,500	$(1.14)	$—	$—	$—
2015(3)	Protective spread	5,000	1,375,000	$4.00	$—	$3.25	$—
2015(3)	Producer three-way collar	2,500	687,500	$—	$3.70	$3.00	$4.09
2015(3)	Producer three-way collar	5,000	1,375,000	$—	$3.77	$3.00	$4.11
2016	Protective spread	2,000	732,000	$4.11	$—	$3.25	$—

(1) For the period January to March 2015.
(2) Represents basis swaps at the sales point of Dominion South.
(3) For the period April to December 2015.

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As of December 31, 2014, 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)
2015(2)	Costless collar	400	72,400	$—	$85.00	$—	$96.50
2015(2)	Costless collar	366	66,300	$—	$85.00	$—	$97.80
2015(2)	Costless collar	150	27,150	$—	$85.00	$—	$96.25
2015(3)	Costless three-way collar	400	73,600	$—	$85.00	$70.00	$96.50
2015(3)	Costless three-way collar	325	59,800	$—	$85.00	$65.00	$97.80
2015(3)	Costless three-way collar	50	9,200	$—	$85.00	$65.00	$96.25
2015(2)	Put spread	700	126,700	$—	$90.00	$70.00	$—
2015	Put spread	250	91,250	$—	$89.00	$69.00	$—
2015(3)	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(4)	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 2015.
(3) For the period July to December 2015.
(4) For the period January to August 2018.

As of December 31, 2014, the following NGLs derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume (in Bbls)	Total of Notional Volume	Base Fixed Price
2015(1)	Fixed price swap	250	68,750	$45.61

(1) For the period April to December 2015.

As of December 31, 2014, 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 January 2014 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 liabilities in December 2013. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

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	For the Years Ended December 31,	
	2014	2013
	(in thousands)	
Current commodity derivative premium put payable	$2,481	$145
Long-term commodity derivative premium payable	4,702	7,000
Total unamortized put premium liabilities	$7,183	$7,145

	For the Year December 31, 2014
	(in thousands)
Put premium liabilities, beginning balance	$7,145
Less:	
Amortization of put premium liabilities	(145)
Additional put premium liabilities	183
Put premium liabilities, ending balance	$7,183

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of December 31, 2014:

	Amortization
	(in thousands)
January to December 2015	$2,481
January to December 2016	2,408
January to December 2017	1,460
January to August 2018	834
Total unamortized put premium liabilities	$7,183

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	2014	2013
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$19,687	$—
Commodity derivative contracts	Other assets	7,815	7,545
Commodity derivative contracts	Current liabilities	—	(3,403)
Commodity derivative contracts	Long-term liabilities	—	(378)
Total derivatives not designated as hedging instruments		$27,502	$3,764

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Years Ended December 31, 2014	2013	2012
		(in thousands)		
Derivatives not designated as hedging instruments				
Commodity derivative contracts	Gain (loss) on commodity derivatives contracts	$19,569	$(4,752)	$7,422
Commodity derivative contracts	Interest expense	—	—	(186)
Total		$19,569	$(4,752)	$7,236

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, par value $0.001 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.

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.

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 subsidiary, 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.

On September 24, 2014, the Company sold 17,000,000 shares of its common stock in an underwritten public offering pursuant to the Company's effective Registration Statement on Form S-3 at a price of $6.25 per share, or $106.3 million before offering costs and expenses. The Company received approximately $101.3 million of proceeds from the offering, net of estimated offering costs and expenses of approximately $5.0 million.

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, par value $0.01 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.

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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, 2014, Gastar USA sold 86,840 shares of Series A Preferred Stock under the ATM Agreement for net proceeds of $2.1 million, resulting in 4,045,000 total shares of Series A Preferred Stock issued for total net proceeds, inception to date, of $78.8 million at December 31, 2014.

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.

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 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 $25.00 per share, plus accrued and unpaid dividends (whether or not declared), up to the redemption date.

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

Gastar USA pays 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, 2014, 2013 and 2012, Gastar USA paid dividends of $8.7 million, $8.5 million and $7.1 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.

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.

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

Gastar USA pays 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 years ended December 31, 2014 and 2013, Gastar USA paid dividends of $5.8 million and $847,000, respectively.

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Other Share Issuances

The following table provides information regarding the issuances and forfeitures of the Company's common stock pursuant to the Gastar Exploration Inc. Long-Term Incentive Plan for the periods indicated:

	For the Years Ended December 31,	
	2014	2013
Other stock issuances:		
Shares of restricted common stock granted	601,473	2,288,179
Shares of restricted common stock vested	1,915,242	762,682
Shares of common stock issued pursuant to PBUs vested, net of forfeitures	472,189	—
Stock options exercised	7,500	10,000
Shares of restricted common stock surrendered upon vesting/exercise (1)	612,612	224,500
Shares of restricted common stock forfeited	47,398	512,862

(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. In connection with the merger, Parent's 2006 Long-Term Stock Incentive Plan 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" (as amended, the "LTIP"). On June 12, 2014, the Company's stockholders approved an amendment and restatement to the LTIP, effective April 24, 2014, to, among other things, increase the number of shares reserved for issuance under the LTIP by 3,000,000 shares. There were 4,561,508 shares available for issuance under the LTIP at December 31, 2014.

Shares Reserved

At December 31, 2014, the Company had 866,600 shares of common stock reserved for the exercise of stock options and 990,658 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.

9. Equity Compensation Plans

Share-Based Compensation Plan

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.

On June 12, 2014, the Company's stockholders approved the Amended and Restated Gastar Exploration Inc. Long-Term Incentive Plan (the "LTIP"). The LTIP permits us to issue stock options, stock appreciation rights, bonus stock awards and any other type of award (including performance-based units, or "PBU's"), which are consistent with the LTIP's purpose to directors, officers and employees of the Company and its subsidiaries.

At December 31, 2014, 4,561,508 shares of common stock were available for future stock-based compensation grants under the LTIP. All shares of common stock issued upon the exercise of stock option grants or vesting of restricted stock grants and PBUs are authorized, issued by the Company and are fully paid and non-assessable.

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Determining Fair Value of Stock Options

There were no stock options granted during the years ended December 31, 2014, 2013 and 2012. However, in prior years, the Company issued stock options as a component of its equity compensation program. As of December 31, 2014, all stock options were vested. In determining the fair value of stock option grants, the Company utilized the following assumptions:

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

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

Expected Volatility. Using the Black-Scholes-Merton valuation model, the Company estimates the volatility of the Company's common stock at the beginning of the quarter in which the stock option is granted. The volatility is based on weighted average historical movements of the Company's common stock 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. The Company has not paid any cash dividends on its common stock 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 2014, 2013 and 2012, the Company used forfeiture rates in determining compensation expense of 25.5%, 14% and 15.5%, respectively.

The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes-Merton valuation pricing model.

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,		
	2014	2013	2012
	(in thousands, except per share data)		
Weighted average grant date fair value per stock option granted	$—	$—	$—
Intrinsic value of stock options exercised (1)	$28	$19	$2
Grant date fair value of stock options vested	$27	$88	$117

(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.

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Stock Option Activity

The following tables summarize certain information related to outstanding stock options under the LTIP as of and for the year ended December 31, 2014:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2013	874,100	$ 11.68		
Granted	—	—		
Exercised	(7,500)	2.60		
Canceled/Expired	—	—		
Forfeited	—	—		
Outstanding at December 31, 2014	866,600	$ 11.75		
Options vested and exercisable at December 31, 2014	866,600	$ 11.75	2.19	$—

	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, 2013	10,000	$ 2.74			
Granted	—	—			
Vested	(10,000)	2.74			
Forfeited	—	—			
Outstanding non-vested options at December 31, 2014	—	$ —	$ —	0	$—

There was no unrecognized expense as of December 31, 2014 for all outstanding options.

Restricted Share Activity

The Company has granted restricted shares of common stock which vest based upon continued service or certain other events. Prior to December 31, 2014, 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. The following table summarizes information related to restricted shares at December 31, 2014:

	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, 2013	3,773,081	$1.82		
Granted	601,473	5.85		
Vested	(1,915,242)	1.83		
Forfeited	(47,398)	3.76		
Outstanding non-vested restricted shares at December 31, 2014	2,411,914	$2.79	8.11	$5,813

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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,		
	2014	2013	2012
	(in thousands, except per share data)		
Weighted average grant date fair value per restricted share	$5.85	$1.30	$2.09
Total fair value of restricted shares vested	$3,497	$2,725	$2,492

Unrecognized compensation expense as of December 31, 2014 for all outstanding restricted share awards is $1.6 million and will be recognized over a weighted average period of 1.43 years.

Performance Based Units Activity

During 2014 and 2013, a portion of long-term incentive grants were in the form of PBUs. The PBUs represent a contractual right to receive shares of the Company's common stock, an amount of cash equal to the fair market value of a share of the Company's common stock, or a combination of shares of the Company'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 the Company'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.

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

	PBUs	Fair Value per Unit
Unvested PBUs at December 31, 2013	1,065,734	$1.56
Granted	280,171	7.34
Vested	(355,247)	1.56
Forfeited	—	—
Unvested PBUs at December 31, 2014	990,658	$3.19

For the year ended December 31, 2014, the Company recognized $1.7 million of compensation expense associated with the PBUs. As of December 31, 2014, the Company had $1.1 million of total unrecognized expense for the PBUs.

Stock-Based Compensation Expense

For the years ended December 31, 2014, 2013 and 2012, the Company recorded stock-based compensation expense for restricted shares, PBUs, and stock options granted using the fair-value method of $4.9 million, $3.4 million and $3.3 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, 2014, the Company had approximately $2.8 million of total unrecognized compensation cost related to unvested restricted shares and PBUs, which is expected to be amortized over the following periods:

	Amount
	(in thousands)
2015	$2,034
2016	663
2017	59
Total	$2,756

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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,		
	2014	2013	2012
	(in thousands)		
Interest expense:			
Cash and accrued	$28,851	$14,130	$1,992
Amortization of deferred financing costs(1)(2)	3,067	2,322	224
Capitalized interest	(4,347)	(3,284)	(1,946)
Total interest expense	$27,571	$13,168	$270

(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. For more information, see Note 4. “Long-Term Debt - Second Amended and Restated Revolving Credit Facility.”

(2) The years ended December 31, 2014 and 2013 include $2.3 million and $716,000, respectively, 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. For more information, 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. For more information, see Note 3. “Property, Plant and Equipment - Chesapeake Acquisition.”

As of December 31, 2014, Chesapeake Energy Corporation did not own any of the Company's outstanding common stock.

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,		
	2014	2013	2012
	(in thousands)		
United States	$50,953	$51,276	$(152,322)
Foreign	—	(1,934)	(1,469)
Total income (loss) before income taxes	$50,953	$49,342	$(153,791)

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The Company did not report any current provision for income taxes for the years ended December 31, 2014, 2013 and 2012. The Company's deferred income tax expense (benefit) consists of the following for the periods presented:

	For the Years Ended December 31,		
	2014	2013	2012
	(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,		
	2014	2013	2012
	(in thousands)		
Expected income tax provision (benefit) at statutory rate	$17,833	$11,655	$(53,827)
State tax, tax effected	803	96	(2,562)
Stock-based compensation expense	(1,291)	605	560
Tax effect of Canadian tax rate differences	—	193	(125)
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	38	(49)	15
Other changes in valuation allowance	(17,383)	(38,777)	55,939
Actual income tax provision	$—	$(16,042)	$—

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

	As of December 31,	
	2014	2013
	(in thousands)	
Deferred tax asset (liability):		
Capital assets	$(134,223)	$(77,456)
Stock-based compensation	4,504	6,501
Net operating loss carry forwards	164,056	122,675
Foreign tax credit carry forwards	50,681	50,681
Valuation allowance	(85,018)	(102,401)
Net deferred tax asset	$—	$—

The Company has approximately $447.0 million of net operating loss carry forwards as of December 31, 2014, which, if not utilized, will expire between 2030 and 2034. For U.S. federal income tax purposes, as of December 31, 2014, 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.

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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. 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, 2014, the Company did not have any material 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.

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.

	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands, except per share and share data)		
Net income (loss) attributable to common stockholders	$36,529	$39,964	$(160,868)
Weighted average shares of common stock outstanding - basic	63,270,733	60,220,115	63,538,362
Incremental shares from unvested restricted shares	2,451,903	2,869,490	—
Incremental shares from outstanding stock options	97,491	26,095	—
Incremental shares from outstanding PBUs	672,462	502,701	—
Weighted average shares of common stock outstanding - diluted	66,492,589	63,618,401	63,538,362
Net income (loss) per share of common stock attributable to common stockholders:			
Basic	$0.58	$0.66	$(2.53)
Diluted	$0.55	$0.63	$(2.53)
Shares of common stock excluded from denominator as anti-dilutive:			
Unvested restricted shares	34,058	3,505	1,831,435
Stock options	—	—	936,967
Total	34,058	3,505	2,768,402

14. Commitments and Contingencies

Contractual Obligations

The Company leases its office facilities and certain office equipment under non-cancelable operating lease agreements terminating in October 2018. For the years ended December 31, 2014, 2013 and 2012, office lease expense totaled approximately $649,000, $372,000 and $377,000, respectively.

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As of December 31, 2014, the Company’s aggregate future minimum annual rental commitments under the non-cancelable leases for the next five years are as follows:

2015	$640
2016	498
2017	187
2018	161
	$1,486

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, was resolved as part of an acquisition transaction which closed on June 7, 2013. Thereafter, the parties to the Chesapeake lawsuit filed stipulation of dismissal of prejudice, and on June 11, 2013, the court entered an order dismissing the case with prejudice. In connection with the resolution of the matter, the Company made an aggregate cash payment of approximately $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.

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 produced from properties that are owned in part by Gastar USA in the Marcellus Shale in Marshall and Wetzel Counties, West Virginia, and requested 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 and maximize the net value of the condensate and NGLs produced 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 had reached an agreement in principle to settle their disputes. The disputes were subsequently settled, on a confidential basis, between both parties on June 17, 2014. Although there were some changes to the contracts, there were no changes to existing contractual fees. After production taxes and lease operating expense reimbursement benefit, the net arbitration settlement amount received by Gastar USA was approximately $8.6 million.

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 sought discretionary review from the Texas Supreme Court, which that court denied on February 27, 2015. 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.

Eagle Natrium LLC v. Gastar Exploration USA, Inc., Cause No. GD-14-7208, In the Court of Common Pleas of Allegheny County, Pennsylvania. On April 22, 2014, Eagle Natrium LLC (“Eagle”), a wholly-owned subsidiary of Axiall Corporation, filed a complaint against Gastar in the Court of Common Pleas of Allegheny County, Pennsylvania seeking to enjoin Gastar's hydraulic fracturing and completion operations on three wells drilled from Gastar's Goudy pad in Marshall County, West Virginia, or conducting any activity that poses a substantial risk of harm to Eagle's brine operations. Gastar is the operator of approximately 13,700 acres in Marshall County, West Virginia, including a 3,300 gross acre oil and gas lease adjacent to Eagle's facilities. Eagle operates a subsurface brine operation which it acquired from the lessor of Gastar's lease. Eagle has asserted its right to relief based on certain of the lessor's rights which were assigned to Eagle by the lessor solely as they relate to the brine and related facilities. The complaint alleges that the contemplated operations of Gastar, which include hydraulic fracturing, pose a danger to the subsurface brine operations of Eagle. All wells drilled to date on this lease, including the wells principally involved in the complaint, were previously approved pursuant to the terms of Gastar's lease. Proved

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undeveloped well locations on this lease accounted for 87.7 Bcfe, or 19%, of the Gastar's total company proved reserves at June 30, 2014. A hearing on the request for preliminary injunction was held over the course of two weeks. After considering the evidence presented at the hearing and the party's briefing, the court issued an order on October 21, 2014 denying the request for a preliminary injunction. On October 30, 2014, Eagle filed a nearly identical lawsuit against Gastar and the West Virginia Department of Environmental Protection ("WVDEP") in the Circuit Court of Marshall County, West Virginia, requesting a temporary restraining order prohibiting Gastar from hydraulically fracturing the same wells that were the subject of the proceeding in Pennsylvania. That same day, the Court held a hearing and granted a temporary restraining order against Gastar and required that Eagle post an $800,000 bond. On December 24, 2014, Circuit Judge David W. Hummel dismissed Gastar from the lawsuit finding that Eagle was collaterally and judicially estopped from maintaining in West Virginia a lawsuit that was essentially identical to the prior lawsuit in Pennsylvania. After further briefing, Judge Hummel dismissed the claims against the WVDEP on December 29, 2014.

After the dismissal of the West Virginia lawsuit, Gastar began completion operations and has since completed the three wells drilled from its Goudy pad that formed the basis of Eagle's complaint. Gastar now plans to move to dismiss the suit in Pennsylvania on account of mootness. Gastar is currently seeking attorney's fees and damages in West Virginia and also plans to seek attorney's fees and damages in Pennsylvania pending disposition of the matter. 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

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI Energy, LLC ("SEI") with respect to our Marshall County, West Virginia production. The initial term of the gas purchase agreement is five years with the option to extend the term of the gas purchase agreement for an additional five year period. Our Marshall County, West Virginia production is dedicated to SEI for the term of the gas purchase agreement. During June 2014, the Company entered into an agreement to include the dedication of all of our Wetzel County, West Virginia production to SEI in addition to our Marshall County, West Virginia production. 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 or William's 200.0 MMcf/d Oak Grove 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, 2014, the Company had total liabilities of $5.6 million related to asset retirement obligations of which $82,000 is recorded as short-term liabilities and $5.5 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.

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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 Company entered into an employment agreement with its Chief Operating Officer on June 19, 2014. The agreements set forth, among other things, annual compensation, and adjustments thereto, bonus payments, fringe benefits, termination and severance provisions.

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,		
	2014	2013	2012
Appalachian Basin	39 %	65 %	72 %
Mid-Continent	61 %	26 %	— %
Hilltop Area, East Texas(1)	— %	9 %	27 %
Powder River Basin(2)	— %	— %	1 %

(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,		
	2014	2013	2012
SEI	50 %	56 %	47 %
Sunoco	37 %	16 %	— %
Clearfield Appalachian	— %	8 %	14 %
ETC	— %	8 %	24 %

SEI purchases the majority of the Company's Appalachian Basin production. There are limited oil, condensate, natural gas and NGLs purchase and transportation alternatives currently available in Appalachia. If SEI was to cease purchasing and transporting the Company's Appalachian Basin 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.

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:

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	For the Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
Cash paid for interest, net of capitalized amounts	$24,632	$7,341	$39
Non-cash transactions:			
Capital expenditures included in accounts payable and accrued drilling costs	$12,777	$582	$4,666
Capital expenditures included in accounts receivable	4,077	(4,077)	(929)
Asset retirement obligation included in oil and natural gas properties	221	(1,302)	1,164
Asset retirement obligation sold/assigned to operator	(645)	(4,354)	(2,227)
Application of advances to operators	58,326	19,755	7,441
Other	(11)	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, 2014 and 2013:

	2014			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$32,327	$35,897	$41,746	$61,448
Income from operations	8,497	12,539	20,413	37,063
Income before provision for income taxes	1,611	5,627	13,425	30,290
Net income	1,611	5,627	13,425	30,290
Dividend on preferred stock	3,576	3,611	3,618	3,619
Net (loss) income attributable to common stockholders	(1,965)	2,016	9,807	26,671
Net (loss) income per share of common stock attributable to common stockholders:				
Basic	$(0.03)	$0.03	$0.16	$0.35
Diluted	$(0.03)	$0.03	$0.15	$0.34
Weighted average shares of common stock outstanding:				
Basic	58,204,532	58,702,982	60,006,903	75,994,979
Diluted	58,204,532	61,922,874	63,399,446	78,577,762

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	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
(Loss) income from operations	(1,849)	13,809	1,626	5,178
(Loss) income before provision for income taxes(1)	(2,456)	53,970	(1,808)	(16,406)
Net (loss) income	(2,456)	53,970	(1,808)	(364)
Dividend on preferred stock	2,130	2,134	2,134	2,980
Net (loss) income attributable to common stockholders	(4,586)	51,836	(3,942)	(3,344)
Net (loss) income per share of common stock attributable to 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.

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,		
	2014	2013	2012
	(in thousands)		
Proved properties:			
United States	$1,124,367	$935,773	$671,193
Total proved properties	1,124,367	935,773	671,193
Unproved properties:			
United States	128,274	96,220	67,892
Total unproved properties	128,274	96,220	67,892
Total oil and natural gas properties	1,252,641	1,031,993	739,085
Less:			
Impairment of proved oil and natural gas properties			
United States	(337,939)	(337,939)	(337,939)
Accumulated depreciation, depletion and amortization	(223,555)	(177,790)	(145,631)
Net capitalized costs	$691,147	$516,264	$255,515

Pursuant to authoritative guidance for accounting for asset retirement obligations, net capitalized costs include related asset retirement costs of approximately $2.4 million, $3.4 million and $4.8 million at December 31, 2014, 2013 and 2012, respectively.

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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,		
	2014	2013	2012
	(in thousands)		
Property acquisition			
Proved(1)	$—	$189,594	$—
Unproved(2)	41,475	71,472	25,676
Exploration	127,384	36,893	10,041
Development	57,913	53,058	111,878
Total costs incurred	$226,772	$351,017	$147,595

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

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,		
	2014	2013	2012
	(in thousands, except per Mcfe data)		
Oil, condensate, natural gas and NGLs sales, including commodity derivatives	$171,418	$87,755	$49,940
Production expenses	(29,735)	(18,113)	(13,408)
Impairment of oil and natural gas properties	—	—	(150,787)
Depreciation, depletion and amortization	(45,765)	(32,158)	(25,195)
Results of producing activities	$95,918	$37,484	$(139,450)
Depreciation, depletion and amortization per MBoe	$12.34	$9.94	$11.41

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 oil and natural gas as of December 31, 2014 and 2013. 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,	
	2014	2013
Natural gas (per MMBtu):		
Henry Hub	$4.35	$3.67
Oil (per Bbl):		
WTI spot	$94.99	96.78

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.

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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, 2014, 2013, and 2012 and includes reserve information for the Appalachian Basin as of December 31, 2014, 2013, and 2012, reserve information for the Mid-Continent as of December 31, 2014 and reserve information for the Hilltop Area of East Texas as of 2012. 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.

The following tables set forth changes in estimated net proved and proved developed and undeveloped reserves for the years ended December 31, 2014, 2013 and 2012:

Change in Proved Reserves	Natural Gas (MMcf) (1)	NGLs (MBbl) (2)	Condensate and Oil (MBbl) (2)	MBoe (3) Equivalents (4)
Proved reserves as of December 31, 2011	91,652	2,757	1,921	19,953
2012 Activity:				
Extensions and discoveries[5]	57,835	2,783	2,439	14,861
Revisions of previous estimates	(6,518)	(348)	(796)	(2,230)
Production	(10,564)	(270)	(177)	(2,208)
Purchases in place	—	—	7	7
Sales in place	(1,395)	—	—	(231)
Proved reserves as of December 31, 2012	131,010	4,922	3,394	30,152
2013 Activity:				
Extensions and discoveries[6]	52,750	2,306	4,385	15,483
Revisions of previous estimates	8,114	714	(337)	1,729
Production	(13,366)	(494)	(515)	(3,237)
Purchases in place	26,961	2,350	7,796	14,639
Sales in place	(24,759)	—	(5)	(4,132)
Proved reserves as of December 31, 2013	180,710	9,798	14,718	54,634
2014 Activity:				
Extensions and discoveries[7]	121,672	9,394	13,137	42,810
Revisions of previous estimates	(2,465)	7,205	1,780	8,574
Production	(11,598)	(800)	(975)	(3,708)
Sales in place	(1,314)	(4)	(24)	(247)
Proved reserves as of December 31, 2014	287,005	25,593	28,636	102,063

(1) Million cubic feet or million cubic feet equivalent, as applicable
(2) Thousand barrels
(3) Thousand barrels of oil, condensate or NGLs equivalent.

(4) 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.

(5) 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.

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(6) Of the 2013 extensions and discoveries, 74% 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.
(7) Of the 2014 extensions and discoveries, 69% resulted from successful drilling results in the Marcellus Shale. The remainder of the 2014 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)	MBoe (3) Equivalents (4)
December 31, 2012				
Proved developed reserves	95,602	3,215.8	1,959	21,109
Proved undeveloped reserves	35,408	1,706	1,435	9,042
Total	131,010	4,922	3,394	30,151
December 31, 2013				
Proved developed reserves	114,195	6,025	5,834	30,892
Proved undeveloped reserves	66,515	3,773	8,884	23,742
Total	180,710	9,798	14,718	54,634
December 31, 2014				
Proved developed reserves	114,564	10,726	6,968	36,789
Proved undeveloped reserves	172,441	14,867	21,668	65,274
Total	287,005	25,593	28,636	102,063

(1) Million cubic feet or million cubic feet equivalent, as applicable
(2) Thousand barrels
(3) Thousand barrels of oil, condensate or NGLs equivalent.
(4) 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, 2014, 2013 and 2012 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,		
	2014	2013	2012
Natural gas, per MMBtu			
Henry Hub	$4.35	$3.67	$2.76
Oil, per barrel:			
WTI spot	$94.99	$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

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disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

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

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

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

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

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

	United States (in thousands)
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	(215,502)
Future net cash flows	1,002,287
10% annual discount for estimated timing of cash flows	(486,458)
Standardized measure of discounted future cash flows	$515,829
December 31, 2014:	
Future cash inflows	$3,855,227
Future production costs	(1,048,554)
Future development costs	(611,602)
Future income taxes	(486,593)
Future net cash flows	1,708,478
10% annual discount for estimated timing of cash flows	(891,739)
Standardized measure of discounted future cash flows	$816,739

(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, 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
Extensions and discoveries, less related costs	369,806
Sale of natural gas and oil, net of production costs	(122,114)
Sales of reserves in place	(1,475)
Revisions of previous quantity estimates	101,044
Net change in income tax	(95,245)
Net change in prices and production costs	59,786
Accretion of discount	(3,996)
Development costs incurred	37,461
Net change in estimated future development costs	(1,277)
Change in production rates (timing) and other	(43,081)
December 31, 2014	$816,739

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

Not applicable.

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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, 2014 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, 2014 based on criteria established in Internal Control—Integrated Framework (2013) 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, 2014 based on the criteria listed herein. The results of management's assessment were reviewed with the Audit Committee of our Board of Directors.

BDO USA, LLP, the independent registered 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.

/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 12, 2015	March 12, 2015

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2014, 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

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We have audited Gastar Exploration Inc.'s (the "Company") internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A. "Management's Report on Internal Control over Financial Reporting". Our responsibility is to express an opinion on the effectiveness of internal control over financial reporting of the Company based on our audit.

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

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

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

In our opinion, Gastar Exploration Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, 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, 2014 and 2013 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014 and our report dated March 12, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
March 12, 2015

Item 9B. Other Information

Revolving Credit Facility Amendment

On March 9, 2015, the Company, together with the parties thereto, entered into a Master Assignment, Agreement and Amendment No. 5 ("Amendment No. 5") to Second Amended and Restated Credit Agreement. Amendment No. 5 amended the Revolving Credit Facility to, among other things, (i) increase the borrowing base from $145.0 million to $200.0 million, (ii) adjust the leverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to September 30, 2016, to 5.25 to 1.00; for the fiscal quarter ending on September 30, 2016, to 5.00 to 1.00; for the fiscal quarter ending on December 31, 2016, to 4.75 to 1.00; for the fiscal quarter ending on March 31, 2017, to 4.25 to 1.00; for the fiscal quarter ending on or after June 30, 2017, to 4.00 to 1.00, (iii) adjust the interest coverage ratio for each fiscal quarter ending on or after March 31, 2015 but prior to March 31, 2016, to 2.00 to 1.00 and for each fiscal quarter ending on or after March 31, 2016, to 2.50 to 1.00, and (iv) add the senior secured leverage ratio covenant, such ratio not to exceed, (a) for each fiscal quarter ending on or after March 31, 2015 but prior to June 30, 2016, 2.25 to 1.00 and (b) for each fiscal quarter ending on or after June 30, 2016, 2.00 to 1.00 provided that this senior secured leverage ratio shall cease to apply commencing with the first fiscal quarter end occurring after June 30, 2016 for which the total leverage ratio is equal to or less than 4.00 to 1.00.

Third Amendment to Employment Agreement

On March 10, 2015, we entered into a Third Amendment (the “Third Amendment”) to the Employment Agreement dated as of April 26, 2005 and amended previously on July 25, 2008 and April 10, 2012 (the “Employment Agreement”) with

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Michael A. Gerlich, our Chief Financial Officer. The Third Amendment changes the formula for determining Mr. Gerlich's severance payment under the Employment Agreement to reflect a previous increase in his target annual bonus and to provide for the severance formula to automatically adjust to reflect any further increases in his target annual bonus that are approved by our Compensation Committee. Specifically, the Second Amendment increases Mr. Gerlich's severance payment to 2.5 times the sum of his annual salary plus an amount equal to his target bonus in effect at such time . A copy of the Third Amendment is filed herewith as Exhibit 10.21.

Amendment to Employee Change of Control Severance Plan

On March 10, 2015, the board of directors of the Company approved the adoption of an amendment (the "COC Severance Plan Amendment") to the Gastar Exploration Inc. Employee Change of Control Severance Plan, as previously amended (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 provide that the target bonus amount uses in the severance payment formula for our Chief Executive Officer, Chief Operating Officer and Chief Financial Officer shall automatically be adjusted to reflect any increases in annual target bonus approved by our compensation committee. 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 and 88% for the Company's Chief Financial Officer and Chief Operating Officer. A copy of the COC Severance Plan Amendment is filed herewith as Exhibit 10.32.

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, 2015, are as follows:

Name	Age	Position
J. Russell Porter (1)	53	President and Chief Executive Officer
Michael A. Gerlich (1)	60	Senior Vice President, Chief Financial Officer and Corporate Secretary
Michael McCown (1)	60	Senior Vice President and Chief Operating Officer
Keith R. Blair	60	Vice President and Exploration Manager
Henry J. Hansen	59	Vice President - Land
John M. Selser Sr.	56	Chairman of the Board
John H. Cassels	67	Director
Randolph C. Coley	68	Director
Stephen A. Holditch	68	Director
Robert D. Penner	71	Director
Jerry R. Schuyler	59	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 23 years of oil and natural gas 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 and director of Petrel Energy Ltd., a publicly-traded exploration and development company listed on the Australian Securities Exchange. He has held no other directorship positions in publicly-traded companies during the last five years. Mr. Porter holds

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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 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 and was promoted to Senior Vice President in June 2013. Mr. Gerlich has over 35 years of oil and natural gas 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 the auditing firm of Deloitte LLP, where the focus of his practice was with energy related clients. Mr. Gerlich served as a member of the board of directors and as the Audit Committee Chairman for Petropoint Energy Partners LP (“Petropoint”), a private upstream oil and gas limited partnership, from November 2012 until Petropoint’s property sale and dissolution in August 2014. 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, an independent oil and natural gas company and the 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 38 years of 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 35 years of oil and natural gas experience. He has extensive working knowledge of oil and natural gas 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 35 years of land management experience. Prior to joining us, Mr. Hansen was Rocky Mountain Land Manager with El Paso Corporation, an oil and natural gas 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 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

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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 38 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 natural 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 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.

Stephen A. Holditch became a member of the Board effective August 8, 2014. Dr. Holditch is a Professor Emeritus in the Harold Vance Department of Petroleum Engineering at Texas A&M University, having retired from the University on January 31, 2013. Dr. Holditch was the Director of the Texas A&M University Energy Institute from 2011 to 2012. From January 2004 to January 2012, Dr. Holditch was head of the Harold Vance Department of Petroleum Engineering at Texas A&M University. In 1995, Dr. Holditch was elected to the National Academy of Engineering, the highest professional honor awarded to an engineer for his innovative work in developing low permeability gas reservoirs. From 1977 to 1997, Dr. Holditch was the President of S.A. Holditch & Associates, Inc., a company specializing in evaluations, completions and stimulation of tight gas reservoirs, to include sandstones, coal seams and shale formations. Schlumberger purchased S.A. Holditch & Associates, Inc. in 1997 and Dr. Holditch worked for Schlumberger as an advisor to top level management until 2004. Dr. Holditch was previously on the board of directors at Matador Petroleum Corporation and is an original shareholder in Matador Resources Company. He was first elected to the board of directors of Matador Resources Company in January 2004 and served as chair of the Operations and Engineering Committee until rotating off the board in 2014. Additionally, from February 2006 to December 2011, Dr. Holditch was on the board of directors of Triangle Petroleum Corporation, an oil and natural gas exploration company. While there, he helped to formulate the strategy and oversee the company's growth before resigning in 2011 to devote more time to Texas A&M University. Dr. Holditch received his B.S., M.S. and Ph.D. in Petroleum Engineering from Texas A&M University in 1969, 1970 and 1976, respectively. Dr. Holditch was selected to be a Distinguish Alumnus from Texas A&M University in 2014. Dr. Holditch was chosen as a director because of his extensive experience in the energy industry and substantial knowledge of petroleum engineering matters.

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 the auditing firm of KPMG LLC, after a career of advising public and private clients on tax and accounting matters for more than 40 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 Inc., 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), an oil and natural gas exploration company. On September 29, 2011 Mr. Penner resigned from the Board of Storm Cat Energy Corporation ("Storm Cat"). He additionally serves on the board of directors of several private companies and the Canadian National Institute for the Blind, an NGO. 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 is a graduate member of the Institute of Corporate Directors. Mr. Penner resides in Calgary, Alberta, Canada. Mr. Penner was chosen as a director 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.

Jerry R. Schuyler became a member of the Board effective August 8, 2014. Mr. Schuyler is currently an independent director for private equity funded Gulf Coast Energy Resources Company, a position he has held since 2010, and also serves as a member of the audit committee. Mr. Schuyler is also currently an independent director for publicly traded Rosetta Resources Inc. ("Rosetta"), an independent oil and natural gas exploration company, a position he has held since December 2013. Mr. Schuyler serves as a member of the compensation committee and the governance committee for Rosetta. Mr. Schuyler previously served as a director for Laredo Petroleum, Inc. ("Laredo") for six years. He joined Laredo in June 2007 as Executive Vice President and Chief Operating Officer. In July 2008, he was promoted to President and Chief Operating Officer. He served in that capacity and as a director of the Laredo board of directors until July of 2013 when he announced his retirement. During Mr. Schuyler's tenure at Laredo, he was instrumental in helping grow Laredo from a private equity financed start-up company into a publicly traded company listed on the NYSE. Mr. Schuyler has a Bachelor of Science degree in Petroleum Engineering from Montana College of Mineral Science and Technology and attended several graduate business courses in the executive program at the Bauer College of Business at the University of Houston. Mr. Schuyler was chosen as a director because of his substantial knowledge of the energy industry and his business, leadership and management expertise.

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

Cease Trade Orders

Mr. Penner served as a director of 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

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.

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, 2014, except that on December 2, 2014, a late Form 4 was filed with respect to Mr. McCown's forfeiture of shares to meet tax obligations in connection with the vesting of restricted stock.

Governance Practices

The Board believes that good corporate governance improves corporate performance and benefits all shareholders.

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Code of Ethics

We have adopted a Code of Conduct and Ethics for all employees, including our Chief Executive Officer, Chief Financial Officer, Chief Operating Officer and other senior financial management. 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), Cassels and Coley, 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 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 Corporate 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”). 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 2014.

Compensation Philosophy and Objectives

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, performance-based units 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, Jerry R. Schuyler 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 2014, 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 2014, the Compensation Committee utilized 2013 peer company data and 2014 published survey sources supplied by Longnecker & Associates ("L&A") in reviewing and making certain compensation decisions. For the purposes of its report, L&A's engagement objectives in 2013 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
- Provide conclusions and recommended considerations 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

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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 incentives, plus long-term incentives), as compared to the updated peer group and published survey data based on industry, size and performance. This was followed by developing conclusions and recommended considerations, which was reported to the Compensation Committee.
Companies reviewed by L&A (the "Peer Group") included:
Abraxas Petroleum Corp.
Approach Resources, Inc.
Bonanza Creek Energy, Inc.
Callon Petroleum Company
Carrizo Oil & Gas Inc.
Contango Oil & Gas Co.
Eclipse Resources Corp.
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 2013 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) 2014 base salaries were 2% above the market 50th percentile of our Peer Group for the CFO and 2% and 15% below the market 50th percentile of our Peer Group for the CEO and COO, respectively, (b) 2014 total cash compensation (base salary, plus the annual cash incentive award) approximated the market 50th percentile of our Peer Group for the CFO and were 7% and 16% below the market 50th percentile of our Peer Group for the CEO and COO, respectively, (c) 2014 long-term equity awards were 36% and 21% above the market 50th percentile of our Peer Group for the CEO and CFO, respectively, and 18% below the market 50th percentile of our Peer Group for the COO, and (d) 2014 total direct compensation (base salary, plus the annual cash incentive award, plus equity incentive awards) was 4% and 7% above the market 50th percentile of our Peer Group for the CEO and CFO, respectively, and was 19% below the market 50th percentile of our Peer Group for the COO. Based upon these findings, the Compensation Committee believes that the individual pay components and total direct compensation levels of the Named Executive Officers in 2014 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 market 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.
L&A also reviewed and provided recommended considerations to the Compensation Committee on the Company's long-term incentive plan, including the amount of long-term incentives to provide the Named Executive Officers and

the form in which those long-term incentive grants were provided to the Named Executive Officers.

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 2014, the Compensation Committee adjusted the base salary amounts for Messrs. Porter, Gerlich and McCown. Messrs. Porter's and McCown's 2014 base salaries were less than the 50th percentile of

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our Peer Group by 2% and 15%, respectively, and Mr. Gerlich's 2014 base salary was 2% above the 50th percentile of our Peer Group.

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 2014 targeted bonus percentage of our CEO is 89% of his respective base salary and the targeted bonus percentages of our CFO and COO are 88% of their respective base salary amounts. For 2014, the Compensation Committee approved a $1.0 million 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 2014, the annual cash incentive awards for Messrs. Porter, Gerlich and McCown was 13%, 1% and 17% below the 50th percentile of our Peer Group, respectively. The larger awards during 2014 were the result of the Company's strong 2014 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 2014 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, 2014. 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 2014 were as follows:

Goal	Threshold	Target	Maximum	Actual	Weighting	
Target average annual production (MMcfe/d)	56.5	62.8	69.1	61.0	10	%
Target proved reserves additions (Bcfe)	85.8	95.3	104.9	307.9	10	%
Average finding costs ($/Mcfe)	$2.60	$2.36	$2.12	$0.72	5	%
Average controllable lifting costs ($/Mcfe)	$0.80	$0.73	$0.66	$0.84	5	%
Operating cash flow ($ in millions)	$72.5	$80.5	$88.6	$65.9	20	%
Operating cash flow per share	$1.15	$1.27	$1.40	$1.04	10	%
Production per share (Mcfe)	0.33	0.36	0.40	0.35	20	%
Reserves per share (Mcfe)	5.97	6.64	7.30	9.68	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 2014, management's bonus pool target was $1.2 million. During 2014, five of the eight target goals were achieved or exceeded, with target proved reserve additions and reserves per share hitting the maximum payout. Our Named Executive Officers were entitled to receive a combined annual cash incentive payout of $1.0 million 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 2015 metrics are expected to be materially similar to those used in 2014.

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.

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During 2014, the stock-based compensation granted to our Named Executive Officers consisted of a combination of restricted shares and performance-based units (“PBUs”). The 2014 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 incentives coupled with an element of shorter term reward. The PBUs represent a contractual right to receive shares of the Company's common stock, an amount of cash equal to the fair market value of a share of the Company's common stock, or a combination of shares of the Company'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 granted prior to 2015 vest equally and settlement is determined annually over a three year period. Any PBUs not vested at each measurement date expire. The Compensation Committee adheres to our policy of only granting stock-based compensation grants during open trading windows.

During 2015, our Compensation Committee approved modification to our PBU program such that PBUs granted to our Named Executive Officers in January 2015 will vest and be measured in full following completion of a three-year period (rather than annual measurement, which had been provided for under prior grants). This modification is intended to further align our executive officers' compensation with the long-term appreciation of the Company's stock price. In addition, the Compensation Committee approved certain changes to the payout schedule relating to the PBUs granted during 2015. However, the payout range remains at 0% to 200% and the awards granted during 2015 are otherwise materially consistent with prior PBU grants.

In 2014, Messrs. Porter, Gerlich and McCown received restricted common share grants of 116,380 shares, 52,586 shares and 43,104 shares, respectively. In addition to restricted common shares, Messrs. Porter, Gerlich and McCown received PBU grants of 116,379, units, 52,586 units and 43,103 units, respectively. The combined fair values of these grants calculated to be 286%, 221% and 182% of Messrs. Porter, Gerlich and McCown's base salaries, respectively, which placed Messrs. Porter and Gerlich 36% and 21%, respectively, above the market 50th percentile and placed Mr. McCown 18% below 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 2014 restricted stock and PBU grants were consistent with this goal.

Upon vesting on January 30, 2015, the second tranche of PBUs granted on January 30, 2013 to Messrs. Porter, Gerlich and McCown settled at the maximum settlement of 200%. Upon vesting on January 30, 2015, the first tranche of PBUs granted on January 31, 2014 to Messrs. Porter, Gerlich and McCown settled at 0% and no shares were issued.

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

Each of our Named Executive Officers is party to an employment agreement which provides for payments and benefits in connection with certain termination of employment.

In addition, 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.

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For additional information regarding our employment agreements and the Severance Plan, see “Narrative Disclosure to Summary 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 June 2014, our shareholders approved the compensation of our Named Executive Officers as described in our 2014 proxy statement, with approximately 68% of shareholder votes cast in favor of our 2014 “say-on-pay” resolution (excluding abstentions and broker non-votes). The Compensation Committee considered these results as evidence of support for our compensation program and decisions as described in our 2014 proxy statement, and as grounds for maintaining a similar approach for 2015.

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

Summary Compensation Table

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, 2014, 2013 and 2012:

Name and Principal Position	Year	Base Salary	Bonus	Restricted Stock and PBUs (1)	All Other Compensation(3)	Total
J. Russell Porter	2014	$535,000	$472,202	$1,529,006	$10,400	$2,546,608
President and Chief	2013	$500,000	$489,378	$1,158,393	$10,200	$2,157,971
Executive Officer	2012	$500,000	$393,750	$750,000	$10,000	$1,653,750
Michael A. Gerlich	2014	$312,000	$273,380	$690,980	$10,400	$1,286,760
Senior Vice President and	2013	$300,000	$234,901	$656,111	$10,200	$1,201,212
Chief Financial Officer	2012	$300,000	$189,000	$375,000	$10,000	$874,000
Michael McCown(2)	2014	$312,000	$273,380	$566,379	$10,400	$1,162,159
Senior Vice President and	2013	$300,000	$221,851	$403,449	$10,033	$935,333
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, 2014, 2013 and 2012 and to Mr. McCown during the years ended December 31, 2014 and 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 2014, see Item 8. “Financial Statements and Supplementary Data, Note 9. Equity Compensation Plans” included in 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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Grants of Plan-Based Awards

The following table shows certain information about the restricted common stock and PBUs granted to our Named Executive Officers during the year ended December 31, 2014.

		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	1/30/2014	—	—	—	—	116,380	$675,004
J. Russell Porter	1/30/2014	—	116,379	232,758	$854,222	—	$—
Michael A. Gerlich	1/30/2014	—	—	—	—	52,586	$305,000
Michael A. Gerlich	1/30/2014	—	52,586	105,172	$385,981	—	$—
Michael McCown	1/30/2014	—	—	—	—	43,104	$250,003
Michael McCown	1/30/2014	—	43,103	86,206	$316,376	—	$—

(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:

Long-Term Incentive Plan. We maintain a long-term incentive plan which provides our Compensation Committee with the flexibility to grant different types of awards in respect of our common stock including, without limitations, stock options, restricted shares and PBUs. For 2014, our Named Executive Officers received awards in the form of restricted shares and PBUs. For a description of the terms of such awards, see “Compensation Discussion & Analysis-Long-Term Stock-Based Compensation.”

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.

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	89	%

Chief Financial Officer	2.50	88	%
Chief Operating Officer	2.50	88	%

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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. We entered into an employment agreement with Michael McCown, our COO, effective June 19, 2014. The agreements with Messrs. Porter, Gerlich and McCown set forth, among other things, annual compensation, and adjustments thereto, minimum bonus payments, fringe benefits, termination and severance provisions. The agreements with Messrs. Porter and Gerlich renew annually; however, they may be terminated at any time with or without cause. The agreement with Mr. McCown had an initial term ending June 19, 2016 and will renew automatically thereafter for additional one-year periods; however, it 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's employment agreement provides that each year he shall be eligible to receive a cash bonus as recommended and approved by the Compensation Committee if the Company and Mr. McCown, as applicable, achieve certain performance targets established by the Compensation Committee.
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 2014.

	Base Salary and Cash Bonuses as a Percentage of Total Compensation	
J. Russell Porter	40	%
Michael A. Gerlich	46	%
Michael McCown	51	%

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Outstanding Equity Awards at Fiscal Year-End 2014

The following table sets forth information about outstanding equity awards held by our Named Executive Officers as of December 31, 2014:

		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(3)	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	—	—	—	—	254,655	$ 1,186,692	—	—
	1/30/2014	—	—	—	—	116,379	$ 84,956.67	—	—
	3/15/2011	—	—	—	—	—	—	41,966	$ 101,138
	1/30/2012	—	—	—	—	—	—	84,459	$ 203,546
	1/30/2013	—	—	—	—	—	—	323,276	$ 779,095
	1/30/2014	—	—	—	—	—	—	116,380	$ 280,476
Michael A. Gerlich(4)	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	—	—	—	—	160,201	$ 746,537	—	—
	1/30/2014	—	—	—	—	52,586	$ 38,387.78	—	—
	3/15/2011	—	—	—	—	—	—	22,482	$ 54,182
	1/30/2012	—	—	—	—	—	—	42,230	$ 101,774
	1/30/2013	—	—	—	—	—	—	161,638	$ 389,548
	1/30/2014	—	—	—	—	—	—	52,586	$ 126,732
Michael McCown(5)	1/30/2013	—	—	—	—	89,080	$ 415,113	—	—
	1/30/2014	—	—	—	—	43,103	$ 31,465.19	—	—
	3/15/2011	—	—	—	—	—	—	12,230	$ 29,474
	1/30/2012	—	—	—	—	—	—	29,279	$ 70,562
	1/30/2013	—	—	—	—	—	—	112,069	$ 270,086
	1/30/2014	—	—	—	—	—	—	43,104	$ 103,881

(1) For purposes of this table, we assumed that the unvested PBUs granted on January 30, 2013 will vest at the target of 100% with a fair value of $4.66 per unit on December 31, 2014 the unvested PBUs granted on January 30, 2014 will vest at the target of 100% with a fair value of $0.73 per unit on December 31, 2014.

(2) The closing price of our common shares on December 31, 2014 was $2.41.

(3)

The 41,966 unvested restricted common shares granted to Mr. Porter on March 15, 2011 vest 100% on March 15, 2015. The 84,459 unvested restricted shares granted to Mr. Porter on January 30, 2012 vest 100% on January 30, 2015. The 323,276 unvested restricted shares granted to Mr. Porter on January 30, 2013 vest 50.0% on January 30, 2015 and 2016, respectively. The 116,380 unvested restricted common shares granted to Mr. Porter on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

(4) The 22,482 unvested restricted common shares granted to Mr. Gerlich on March 15, 2011 vest 100% on March 15, 2015. The 42,230 unvested restricted shares granted to Mr. Gerlich on January 30, 2012 vest 100% on January 30,

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2015. The 161,638 unvested restricted common shares granted to Mr. Gerlich on January 30, 2013 vest 50% on January 30, 2015 and 2016, respectively. The 52,586 unvested restricted common shares granted to Mr. Gerlich on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

(5) The 12,230 unvested restricted common shares granted to Mr. McCown on March 15, 2011 vest 100% on March 15, 2015. The 29,279 unvested restricted common shares granted to Mr. McCown on January 30, 2012 vest 100% on January 30, 2015. The 112,069 unvested restricted common shares granted to Mr. McCown on January 30, 2013 vest 50% on January 30, 2015 and 2016, respectively. The 43,104 unvested restricted common shares granted to Mr. McCown on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

Stock and PBUs Vested for 2014

During the year ended December 31, 2014, our Named Executive Officers exercised no stock options. The following restricted common shares vested to the benefit of our Named Executive Officers during 2014:

	Stock Awards			
Name	Grant Date	Vesting Date	Number of Shares Acquired on Vesting	Value Realized on Vesting (1)
J. Russell Porter	3/26/2010	3/26/2014	31,250	$171,875
	3/15/2011	3/15/2014	41,967	$216,969
	1/30/2012	1/30/2014	84,460	$489,868
	1/30/2013	1/30/2014	161,638	$937,500
Michael A. Gerlich	3/26/2010	3/26/2014	21,875	$120,313
	3/15/2011	3/15/2014	22,482	$116,232
	1/30/2012	1/30/2014	42,229	$244,928
	1/30/2013	1/30/2014	80,819	$468,750
Michael McCown	8/5/2010	8/5/2014	5,000	$33,250
	3/15/2011	3/15/2014	12,230	$63,229
	1/30/2012	1/30/2014	29,280	$169,824
	1/30/2013	1/30/2014	56,034	$324,997

(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.

	Performance Based Units			
Name	Grant Date	Vesting Date	Number of Shares Acquired on Vesting(1)	Value Realized on Vesting(2)
J. Russell Porter	1/30/2013	1/30/2014	254,656	$1,477,005
Michael A. Gerlich	1/30/2013	1/30/2014	160,202	$929,172
Michael McCown	1/30/2013	1/30/2014	89,082	$516,676

(1) The first tranche of the January 30, 2013 PBU grant vested at 200% of the amount granted.

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

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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, 2014, 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.

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	$2,407,500	$3,033,450	$—	$2,407,500	$2,407,500
Accrued Vacation	5,144	5,144	5,144	5,144	5,144
Paid health and medical	32,238	32,238	—	32,238	32,238
Parachute tax gross-up payment (5)	—	1,247,663	—	—	—
Equity compensation (6)	—	2,258,450	—	—	—
Total	$2,444,882	$6,576,945	$5,144	$2,444,882	$2,444,882
Michael A. Gerlich:					
Salary	$1,466,400	$1,466,400	$—	$1,466,400	$1,466,400
Accrued Vacation	16,500	16,500	16,500	16,500	16,500
Paid health and medical	32,238	32,238	—	32,238	32,238
Parachute tax gross-up payment (5)	—	813,395	—	—	—
Equity compensation (6)	—	1,185,052	—	—	—
Total	$1,515,138	$3,513,585	$16,500	$1,515,138	$1,515,138
Michael McCown:					
Salary	$780,000	$1,466,400	$—	$780,000	$780,000
Accrued Vacation	1,350	1,350	1,350	1,350	1,350
Paid health and medical	32,238	32,238	—	32,238	32,238
Parachute tax gross-up payment (5)	—	931,622	—	—	—
Equity compensation (6)	—	792,565	—	—	—
Total	$813,588	$3,224,175	$1,350	$813,588	$813,588

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(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, 2014, Mr. Porter's severance was calculated by multiplying $535,000 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, 2014, the cost for health and medical coverage for Mr. Porter as an employee was $1,791 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, 2014, Mr. Porter had available 2.2 days of accrued but unused vacation pay. In addition, effective on Mr. Porter's termination for any reason other than if 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, 2014, Mr. Porter had no unvested stock options to acquire common shares and he had no vested stock options that were "in-the-money" that could be exercised upon his termination of employment. On December 31, 2014, he had 566,082 unvested restricted common shares, which would be canceled upon his termination. On December 31, 2014, Mr. Porter had 152,278 unvested PBUs that could potentially vest upon termination and 204,913 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 of (1) his highest annual base salary in effect at any time during the one year period preceding his termination (at December 31, 2014, this amount was $312,000) and (2) his target bonus amount of 88% of his base salary ($274,560). 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, 2014 the maximum cost over the 18-month period was $1,791 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, 2014, Mr. Gerlich had 12.22 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, 2014, Mr. Gerlich did not have any unvested options and had no vested options that were "in-the-money" that could be exercised upon his termination of employment. Additionally, on December 31, 2014, he had 278,936 unvested restricted common shares, which would be canceled upon his termination. On December 31, 2014, Mr. Gerlich had 89,494 unvested PBUs that could potentially vest upon termination and 115,157 unvested PBUs, which would be canceled upon his termination.

Per Mr. McCown's employment agreement, if he is involuntarily terminated for any reason other than for Cause (as defined below), he will be entitled to a lump sum severance payment equal to the product of 2.5 times his highest annual base salary in effect at the time of his termination (at December 31, 2014, this amount was $312,000). If Mr. McCown 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. McCown 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. McCown 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, 2014 the maximum cost over the 18-month period was $1,791 per month. In addition, Mr. McCown 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, 2014, Mr. McCown had 1 day of available accrued but unused vacation pay. On December 31, 2014, Mr. McCown had 196,682 unvested restricted common shares, which would be canceled upon his termination. On December 31, 2014, Mr. McCown had 53,999 unvested PBUs that could potentially vest upon termination and 73,275 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 (or, in certain limited circumstances, during the six month period prior to 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 89% target bonus at December 31, 2014 were $535,000 and $476,150, respectively. Mr. Gerlich's severance period is 2.5 years, and his annual salary and 88% target bonus at December 31, 2014 were $312,000

and $274,560, respectively. Mr. McCown's severance period is 2.5 years, and his annual salary and 88% target bonus at December 31, 2014 were $312,000 and $274,560, 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 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. 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, 2014. As of December 31, 2014, 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, Gerlich or McCown 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 Messrs. Porter and Gerlich that were already vested as of December 31, 2014, would remain eligible for exercise following his termination of employment.

(4) Per their respective employment agreements, if Messrs. Porter's, Gerlich's or McCown'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, Gerlich's or McCown'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 2010-2014. In making the calculation, the following assumptions were used: (a) the change of control occurred on December 31, 2014, (b) the closing price of our stock was $2.41 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, Mr. McCown's "base amount" was calculated using the average of the 2010-2014 compensation. In making the calculation, the following assumptions were used: (a) the change of control occurred on December 31, 2014, (b) the closing price of our stock was $2.41 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, 2014. As of December 31, 2014, 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, 2014 or $2.41 per common share.

The employment agreements of Messrs. Porter, Gerlich and McCown generally use the following terms:
"Reasonable Cause" or "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 (or, in the case of Mr. McCown, any crime involving moral turpitude); (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.

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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 (or, in certain limited circumstances, during the six months prior to such 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 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.
Mr. McCown's employment agreement provides for non-competition and non-solicitation covenants which are in effect during the term of his employment and for a one-year period thereafter.

Risk Assessment

The Compensation Committee uses the structural elements set forth in Part III of this 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 2014, 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, 2014, non-employee directors received the following fees:

- $3,750 per month, paid semi-annually;
- An aggregate of $25,000 per year for the Chairman of the Board;
- An aggregate of $15,000 for the Chairman of the Audit Committee;

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- An aggregate of $9,000 per year for the Chairman of the Compensation Committee;
- An aggregate of $7,500 for the Chairman of the Nominating and Corporate Governance Committee; and
- $1,550 for each meeting of the Board attended in person, $1,000 for each meeting attended telephonically and $1,000 for each committee meeting attended in person.

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, 2014:

Director Compensation Table

Director	Fees Earned or Paid in Cash	Shares of Common Stock[1]	Total
John H. Cassels	$67,750	$100,000	$167,750
Randolph C. Coley	$69,800	$100,000	$169,800
Stephen A. Holditch	$23,850	$200,000	$223,850
Robert D. Penner	$74,700	$100,000	$174,700
Jerry R. Schuyler	$24,850	$200,000	$224,850
John M. Selser	$86,300	$100,000	$186,300

(1) 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, 2014, 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, 2014:

Name	Grant Date	Option Awards				Stock Awards	
		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	—	—	—	—	4,496	$10,835
	1/30/2012	—	—	—	—	8,446	$20,355
	1/30/2013	—	—	—	—	43,103	$103,878
	11/11/2013	—	—	—	—	8,667	$20,887
	1/30/2014	—	—	—	—	17,241	$41,551
Randolph C. Coley(3)	1/14/2010	40,000	—	$4.27	1/14/2020	—	—
	3/15/2011	—	—	—	—	4,496	$10,835
	1/30/2012	—	—	—	—	8,446	$20,355
	1/30/2013	—	—	—	—	43,103	$103,878
	11/11/2013	—	—	—	—	8,667	$20,887
	1/30/2014	—	—	—	—	17,241	$41,551
Stephen A. Holditch(4)	8/8/2014	—	—	—	—	32,206	$77,616
Robert D. Penner(5)	7/9/2007	40,000	—	$10.95	7/9/2017	—	—
	3/19/2009	15,000	—	$2.60	3/19/2019	—	—
	3/15/2011	—	—	—	—	4,496	$10,835
	1/30/2012	—	—	—	—	8,446	$20,355
	1/30/2013	—	—	—	—	43,103	$103,878
	11/11/2013	—	—	—	—	8,667	$20,887
	1/30/2014	—	—	—	—	17,241	$41,551
Jerry R. Schuyler(6)	8/8/2014	—	—	—	—	32,206	$77,616
John M. Selser Sr.(7)	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	—	—
	3/15/2011	—	—	—	—	4,496	$10,835
	1/30/2012	—	—	—	—	8,446	$20,355
	1/30/2013	—	—	—	—	43,103	$103,878
	11/11/2013	—	—	—	—	17,333	$41,773
	1/30/2014	—	—	—	—	17,241	$41,551

(1) The closing price of our common shares on December 31, 2014 was $2.41.

(2) The 4,496 unvested restricted common shares granted to Mr. Cassels on March 15, 2011 vest 100% on March 15, 2015. The 8,446 unvested restricted shares granted to Mr. Cassels on January 30, 2012 vest 100% on January 30, 2015. The 43,103 unvested restricted common shares granted to Mr. Cassels on January 30, 2013 vest 50% on January 30, 2015 and 2016, respectively. The 8,667 unvested restricted common shares granted to Mr. Cassels on November 11, 2013 vest 50% on November 11, 2015 and 2016, respectively. The 17,241 unvested restricted common shares granted to Mr. Cassels on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

(3)

The 4,496 unvested restricted common shares granted to Mr. Coley on March 15, 2011 vest 100% on March 15, 2015. The 8,446 unvested restricted common shares granted to Mr. Coley on January 30, 2012 vest 100% on January 30, 2015. The 43,103 unvested restricted common shares granted to Mr. Coley on January 30, 2013 vest 50% on January 30, 2015 and 2016, respectively. The 8,667 unvested restricted common shares granted to Mr. Coley on November 11, 2013 vest 50% on November 11, 2015 and 2016, respectively. The 17,241 unvested restricted common shares granted to Mr. Coley on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

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(4) The 32,206 unvested restricted common shares granted to Mr. Holditch on August 8, 2014 vest 33.3% on August 8, 2015, 2016 and 2017, respectively.

(5) The 4,496 unvested restricted common shares granted to Mr. Penner on March 15, 2011 vest 100% on March 15, 2015. The 8,446 unvested restricted common shares granted to Mr. Penner on January 30, 2012 vest 100% on January 30, 2015. The 43,103 unvested restricted common shares granted to Mr. Penner on January 30, 2013 vest 50% on January 30, 2015 and 2016, respectively. The 8,667 unvested restricted common shares granted to Mr. Penner on November 11, 2013 vest 50% on November 11, 2015 and 2016, respectively. The 17,241 unvested restricted common shares granted to Mr. Penner on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

(6) The 32,206 unvested restricted common shares granted to Mr. Schuyler on August 8, 2014 vest 33.3% on August 8, 2015, 2016 and 2017, respectively.

(7) The 4,496 unvested restricted common shares granted to Mr. Selser on March 15, 2011 vest 100% on March 15, 2015. The 8,446 unvested restricted common shares granted to Mr. Selser on January 30, 2012 vest 100% on January 30, 2015. The 43,103 unvested restricted common shares granted to Mr. Selser on January 30, 2013 vest 50% on January 30, 2015 and 2016, respectively. The 17,333 unvested restricted common shares granted to Mr. Selser on November 11, 2013 vest 50% on November 11, 2015 and 2016, respectively. The 17,241 unvested restricted common shares granted to Mr. Selser on January 30, 2014 vest 33.3% on January 30, 2015, 2016 and 2017, respectively.

For the year ending December 31, 2015, 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	$70,000
Chairman of Board annual retainer	$35,000
Chairman of Audit Committee annual retainer	$15,000
Chairman of Compensation Committee annual retainer	$10,000
Chairman of Nominating and Corporate Governance Committee annual retainer	$10,000
Chairman of Reserves Review Committee	$10,000

There will be no additional amounts paid for meeting or committee attendance.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2014, Messrs. Cassels, Coley and Selser each served as members of the Compensation Committee during all of the year and Mr. Schuyler served from his election on August 8, 2014 to December 31, 2014. 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/ Jerry R. Schuyler
/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;

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- 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.

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 80,195,695 shares of common stock, 4,045,000 shares of Series A Preferred Stock and 2,140,000 shares of Series B Preferred Stock outstanding on March 11, 2015. To the knowledge of our directors and executive officers, as of March 11, 2015, 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	Common Stock Percent of Shares Outstanding	Series A Preferred Stock Amount and Nature of Beneficial Ownership	Series A Preferred Stock Percent of Shares Outstanding	Series B Preferred Stock Amount and Nature of Beneficial Ownership	Series B Preferred Stock Percent of Shares Outstanding
Our greater than 5% shareholders:						
Global Undervalued Securities Master Fund, L.P.(1)	6,256,580	7.8%				
301 Commerce Street, Suite 1900						
Fort Worth, Texas 76109						
BlackRock, Inc.(2)	4,189,832	5.2%				
55 East 52nd Street						
New York, NY 10022						
Our non-employee directors (3):						
John H. Cassels (4)	161,275	*	—	—%	—	—%
Randolph C. Coley (5)	208,130	*	—	—%	—	—%
Stephen A. Holditch(6)	100,823	*	—	—%	—	—%
Robert D. Penner (7)	263,774	*	—	—%	—	—%
Jerry R. Schuyler(8)	73,873	*	—	—%	—	—%
John M. Selser Sr.(9)	315,554	*	3,000	*	—	—%
Our executive officers(2):						
J. Russell Porter, President and Chief Executive Officer(10)	2,852,500	3.5%	7,459	*	2,000	*
Michael A. Gerlich, Senior Vice President and Chief Financial Officer(11)	1,393,579	1.7%	2,525	*	2,000	*
Michael McCown, Senior Vice President and Chief Operating Officer(12)	767,978	*	11,655	*	1,535	*
Our directors and executive officers, as a group (9 persons)	5,962,790	7.4%	24,639	*	5,535	*

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* Less than 1%.

(1) Based upon a Schedule 13D filed in respect of Gastar Exploration Inc. on January 22, 2015, as amended. Voting and dispositive power is shared with Kleinheinz Capital Partners, Inc., John B. Kleinheinz and Fred N. Reynolds.
(2) Based upon a Schedule 13G filed in respect of Gastar Exploration Inc. on February 3, 2015.

(3) 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.

(4) As of March 11, 2015, Mr. Cassels owned 73,398 common shares directly and beneficially held 87,877 unvested restricted common shares. Individuals holding unvested restricted common shares have the right to vote those common shares.

(5) As of March 11, 2015, Mr. Coley owned 80,253 common shares directly, beneficially held 87,877 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, 2015 regardless of trading price. Individuals holding unvested restricted common shares have the right to vote those common shares.

(6) As of March 11, 2015, Mr. Holditch owned 26,950 common shares directly and beneficially held 73,873 unvested restricted common shares. Individuals holding unvested restricted common shares have the right to vote those common shares.

(7) As of March 11, 2015, Mr. Penner owned 120,898 common shares directly, beneficially held 87,876 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, 2015 regardless of trading price. Individuals holding unvested restricted common shares have the right to vote those common shares.

(8) As of March 11, 2015, Mr. Schuyler beneficially held 73,873 unvested restricted common shares. Individuals holding unvested restricted common shares have the right to vote those common shares.

(9) As of March 11, 2015, Mr. Selser owned 137,412 common shares directly, beneficially held 96,542 unvested restricted common shares and 6,600 common shares in trust, and held stock options to purchase 75,000 common shares, all of which currently are vested and exercisable as of March 11, 2015 regardless of trading price. Individuals holding unvested restricted common shares have the right to vote those common shares. Additionally, as of March 11, 2015, Mr. Selser directly owned 3,000 shares of Gastar 8.625% Series A Cumulative Preferred Stock.

(10) As of March 11, 2015, Mr. Porter owned 1,383,479 common shares directly, beneficially held 567,650 unvested restricted common shares and 150,000 common shares in trust and held stock options to purchase 260,000 common shares, all of which currently are vested and exercisable as of March 11, 2015 regardless of trading price. As of March 11, 2015, Mr. Porter also held 491,371 unvested PBUs. Individuals holding unvested restricted common shares have the right to vote those common shares. Additionally, as of March 11, 2015, Mr. Porter directly owned 7,459 shares of Gastar USA 8.625% Series A Cumulative Preferred Stock and 2,000 shares of Gastar 10.75% Series B Cumulative Preferred Stock.

(11) As of March 11, 2015, Mr. Gerlich owned 719,228 common shares directly, beneficially held 273,777 unvested restricted common shares and held stock options to purchase 150,000 common shares, all of which currently are vested and exercisable as of March 11, 2015 regardless of trading price. As of March 11, 2015, Mr. Gerlich also held 250,574 unvested PBUs. Individuals holding unvested restricted common shares have the right to vote those common shares. Additionally, as of March 11, 2015, Mr. Gerlich directly owned 2,525 shares of Gastar 8.625% Series A Cumulative Preferred Stock and 2,000 shares of Gastar 10.75% Series B Cumulative Preferred Stock.

(12) As of March 11, 2015, Mr. McCown owned 306,486 common shares directly, beneficially held 242,834 unvested restricted common shares and held 219,108 unvested PBUs. Individuals holding unvested restricted common shares have the right to vote those common shares. Additionally, as of March 11, 2015, Mr. McCown directly owned 11,655 shares of Gastar 8.625% Series A Cumulative Preferred Stock and 1,535 shares of Gastar 10.75% Series B 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, 2014:

Plan Category	Number of Securities to be issued upon	Weighted-average exercise price of outstanding	Number of securities remaining available for future issuance

	exercise of outstanding options, warrants and rights (a)	options, warrants and rights (b)	under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	866,600	$ 11.75	5,428,108
Equity compensation plans approved by security holders	990,658	n/a	6,418,766
Equity compensation plans not approved by security holders	—	—	—
Total	1,857,258	5.49	6,418,766

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Item 13. Certain Relationships and Related Transactions and Director Independence

Certain Relationships and Related Transactions

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, among other factors it deems appropriate, (1) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances, (2) the extent of the related party's interest in the transaction and (3) whether the transaction is material to the Company. 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.

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. 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.

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, 2014 and 2013 were:

	For the Years Ended December 31,	
	2014	2013
	(in thousands)	
Audit fees	$365	$609
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$365	$609

The audit fees for the years ended December 31, 2014 and 2013 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 2014 include $34,000 of audit services related to arbitration settlement and financing activities and audit fees for 2013 include 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 certain 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:

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The financial statements are contained under Item 8. "Financial Statements and Supplementary Data" included in 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).
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).

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Exhibit Number	Description
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).
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).
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. 001-35211).
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	Agreement, Waiver and Amendment No. 3 to Second Amended and Restated Credit Agreement, dated as of March 12, 2014, among the Company, the Guarantors party thereto, the Lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender, and as Issuing Lender (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on March 13, 2014. File No. 001-35211).

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Exhibit Number	Description
10.7	Master Assignment, Agreement and Amendment No. 4 to Second Amended and Restated Credit Agreement, dated as of August 13, 2014, among the Company, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender, Issuing Lender, and Lender, IBERIABANK as Lender, Comerica Bank as Lender, and ING Capital LLC as Lender (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on August 15, 2014. File No. 001-35211).
10.8†	Master Assignment, Agreement and Amendment No. 5 to Second Amended and Restated Credit Agreement, dated as of March 9, 2015, among the Company, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender, Issuing Lender, and Lender, IBERIABANK as Lender, Comerica Bank as Lender, ING Capital LLC as Lender and Barclays Bank PLC as Lender.
10.9	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).
10.10	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).
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15*	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).
10.16*	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).

10.17*	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).
10.18*	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).
10.19*	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).
10.20*	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).
10.21*†	Third Amendment to Employment Agreement entered into by and between Gastar Exploration Inc. and Michael A. Gerlich as of March 10, 2015.
10.22*	Employment Agreement, dated as of June 19, 2014, between Gastar Exploration Inc. and Michael McCown (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on June 23, 2014. File No. 001-35211).

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Exhibit Number	Description
10.23*	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).
10.24*†	Form of Gastar Exploration Inc. Performance Unit Agreement (graded vesting).
10.25*†	Form of Gastar Exploration Inc. Performance Unit Agreement (cliff vesting).
10.26*	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).
10.27*	Amended and Restated Gastar Exploration Inc. Long-Term Incentive Plan (incorporated by reference to Annex A of the Definitive Proxy Statement on Schedule 14A filed with the SEC on May 2, 2014. File No. 001-35211).
10.28*	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on September 15, 2014. File No. 001-35211).
10.29*	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).
10.30*	First Amendment to Amended and Restated Gastar Exploration Ltd. Employee Change of Control Severance Plan, dated April 11, 2012 and effective January 1, 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. 001-35211).
10.31*	Second Amendment to Amended and Restated Gastar Exploration Inc. Employee Change of Control Severance Plan, dated March 12, 2014 and effective March 1, 2014 (incorporated by reference to Exhibit 10.27 of the Annual Report on Form 10-K filed with SEC on March 13, 2014. File No. 001-35211).
10.32*†	Third Amendment to Amended and Restated Gastar Exploration Inc. Employee Change of Control Severance Plan, dated March 10, 2015.
10.33*	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).
10.34*	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).
10.35	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 (incorporated by reference to Exhibit 10.30 of the Annual Report on Form 10-K filed with the SEC on March 13, 2014. File No. 001-35211).
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 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 19, 2015.

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Exhibit Number	Description
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 Commission 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.

GASTAR EXPLORATION INC.

/s/ J. RUSSELL PORTER
J. Russell Porter, President and Chief
Executive Officer
(Duly authorized officer and principal
executive officer)
March 12, 2015

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

Name	Title	Date
/s/ J. RUSSELL PORTER J. Russell Porter	President, Chief Executive Officer, Chief Operating Officer (principal executive officer) and Director	March 12, 2015
/s/ MICHAEL A. GERLICH Michael A. Gerlich	Senior Vice President, Chief Financial Officer and Corporate Secretary (principal financial and accounting officer)	March 12, 2015
/s/ JOHN M. SELSER SR. John M. Selser Sr.	Chairman of the Board	March 12, 2015
/s/ JOHN H. CASSELS John H. Cassels	Director	March 12, 2015
/s/ RANDOLPH C. COLEY Randolph C. Coley	Director	March 12, 2015
/s/ STEPHEN A. HOLDITCH Stephen A. Holditch	Director	March 12, 2015
/s/ ROBERT D. PENNER Robert D. Penner	Director	March 12, 2015
/s/ JERRY R. SCHUYLER Jerry R. Schuyler	Director	March 12, 2015