Gastar Exploration Inc.
Form 10-Q
November 06, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 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)

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 o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Yes o No ý

The total number of outstanding common shares, $0.001 par value per share, as of November 2, 2014 was 78,861,678.

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GASTAR EXPLORATION INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2014
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Unless otherwise indicated or required by the context, (i) for any date or period prior to January 31, 2014,"Gastar," the "Company," "we," "us," "our" and similar terms refer collectively to Gastar Exploration, Inc.(formerly known as Gastar Exploration Ltd.) and its subsidiaries, including Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.), and for any date or period after January 31, 2014, such terms refer collectively to Gastar Exploration Inc. and its subsidiaries, (ii) "Gastar USA" refers to Gastar Exploration USA, Inc., which until January 31, 2014 was a first-tier subsidiary of Gastar Exploration, Inc. and primary operating company as of December 31, 2013, (iii) "Parent" refers to Gastar Exploration, Inc., (iv) all dollar amounts appearing in this Form 10-Q are stated in United States dollars ("U.S. dollars") unless otherwise noted and (v) all financial data included in this Form 10-Q have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar USA as part of a reorganization to eliminate the holding company corporate structure of Parent. Pursuant to the merger agreement, shares of Parent's common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to "Gastar Exploration Inc." Gastar Exploration Inc., together with its subsidiary, owns and will continue to conduct Gastar's business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger.

General information about us can be found on our website at www.gastar.com. The information available on or through our website, or about us on any other website, is neither incorporated into, nor part of, this report. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings that we make with the U.S. Securities and Exchange Commission ("SEC"), as well as any amendments and exhibits to those reports, will be available free of charge through our website as soon as reasonably practicable after we file or furnish them to the SEC. Information is also available on the SEC website at www.sec.gov for our U.S. filings.

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Glossary of Terms

AMI	Area of mutual interest, an agreed designated geographic area where joint venturers or other industry partners have a right of participation in acquisitions and operations
Bbl	Barrel of oil, condensate or NGLs
Bbl/d	Barrels of oil, condensate or NGLs per day
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
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 six 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
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. FINANCIAL INFORMATION

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

	September 30, 2014	December 31, 2013
	(Unaudited)	
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$46,598	$ 32,393
Accounts receivable, net of allowance for doubtful accounts of $0 and $507, respectively	21,859	21,656
Commodity derivative contracts	2,735	—
Prepaid expenses	1,842	1,145
Total current assets	73,034	55,194
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	119,368	96,220
Proved properties	1,048,756	935,773
Total oil and natural gas properties	1,168,124	1,031,993
Furniture and equipment	2,991	2,691
Total property, plant and equipment	1,171,115	1,034,684
Accumulated depreciation, depletion and amortization	(550,944)	(517,171)
Total property, plant and equipment, net	620,171	517,513
OTHER ASSETS:		
Commodity derivative contracts	1,444	7,545
Deferred charges, net	2,785	2,950
Advances to operators and other assets	13,258	6,733
Total other assets	17,487	17,228
TOTAL ASSETS	$710,692	$ 589,935
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$18,266	$ 11,046
Revenue payable	10,456	12,514
Accrued interest	10,512	3,504
Accrued drilling and operating costs	4,166	8,756
Advances from non-operators	11,681	9,259
Commodity derivative contracts	419	3,403
Commodity derivative premium payable	1,966	145
Asset retirement obligation	81	633
Other accrued liabilities	3,092	4,844
Total current liabilities	60,639	54,104
LONG-TERM LIABILITIES:		
Long-term debt	314,704	312,994
Commodity derivative contracts	882	378
Commodity derivative premium payable	5,327	7,000
Asset retirement obligation	5,887	5,430

Total long-term liabilities	326,800	325,802
Commitments and contingencies (Note 12)		
STOCKHOLDERS' EQUITY:		
Preferred stock, 40,000,000 shares authorized		
Series A Preferred stock, $0.01 par value; 10,000,000 shares authorized; 4,045,000 and 3,958,160 shares issued and outstanding at September 30, 2014 and December 31, 2013, respectively, with liquidation preference of $25.00 per share	41	40
Series B Preferred stock, $0.01 par value; 10,000,000 shares authorized; 2,140,000 shares issued and outstanding at September 30, 2014 and December 31, 2013, respectively, with liquidation preference of $25.00 per share	21	21
Common stock, $0.001 par value; 275,000,000 shares authorized; 78,862,165 and 61,211,658 shares issued and outstanding at September 30, 2014 and December 31, 2013, respectively	78	61
Additional paid-in capital	568,078	464,730
Accumulated deficit	(244,965)	(254,823)
Total stockholders' equity	323,253	210,029
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$710,692	$ 589,935

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands, except share and per share data)			
REVENUES:				
Oil and condensate	$22,793	$9,381	$61,913	$22,731
Natural gas	7,151	10,099	40,129	30,113
NGLs	5,139	4,623	16,689	10,415
Total oil, condensate, natural gas and NGLs revenues	35,083	24,103	118,731	63,259
Gain (loss) on commodity derivatives contracts	6,663	(5,263)	(8,761)	(2,229)
Total revenues	41,746	18,840	109,970	61,030
EXPENSES:				
Production taxes	1,558	1,319	5,489	3,112
Lease operating expenses	4,136	2,190	13,057	6,196
Transportation, treating and gathering	397	1,098	3,168	3,386
Depreciation, depletion and amortization	11,111	8,467	33,773	21,428
Accretion of asset retirement obligation	129	142	376	358
General and administrative expense	4,002	3,998	12,658	11,964
Litigation settlement expense	—	—	—	1,000
Total expenses	21,333	17,214	68,521	47,444
INCOME FROM OPERATIONS	20,413	1,626	41,449	13,586
OTHER INCOME (EXPENSE):				
Gain on acquisition of assets at fair value	—	—	—	43,712
Interest expense	(6,991)	(3,439)	(20,794)	(7,593)
Investment income and other	4	8	15	16
Foreign transaction loss	(1)	(3)	(7)	(15)
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES	13,425	(1,808)	20,663	49,706
Provision for income taxes	—	—	—	—
NET INCOME (LOSS)	13,425	(1,808)	20,663	49,706
Dividends on preferred stock	(3,618)	(2,134)	(10,805)	(6,398)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$9,807	$(3,942)	$9,858	$43,308
NET INCOME (LOSS) PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:				
Basic	$0.16	$(0.07)	$0.17	$0.71
Diluted	$0.15	$(0.07)	$0.16	$0.68
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:				
Basic	60,006,903	57,359,357	58,982,709	61,159,117
Diluted	63,399,446	57,359,357	62,306,480	63,971,038

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

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

	For the Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$20,663	$49,706
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	33,773	21,428
Stock-based compensation	3,704	2,540
Mark to market of commodity derivatives contracts:		
Total loss on commodity derivatives contracts	8,761	2,229
Cash settlements of matured commodity derivatives contracts, net	(7,705)	5,929
Cash premiums paid for commodity derivatives contracts	(185)	(102)
Amortization of deferred financing costs	2,270	1,790
Accretion of asset retirement obligation	376	358
Settlement of asset retirement obligation	(580)	—
Gain on acquisition of assets at fair value	—	(43,712)
Changes in operating assets and liabilities:		
Accounts receivable	(4,242)	(1,549)
Prepaid expenses	(697)	481
Accounts payable and accrued liabilities	4,143	141
Net cash provided by operating activities	60,281	39,239
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of oil and natural gas properties	(100,818)	(77,813)
Advances to operators	(43,337)	(13,104)
Acquisition of oil and natural gas properties - refund (expenditure)	4,209	(78,809)
Proceeds from sale of natural gas and oil properties	3,077	70,708
Proceeds from (payments to) non-operators	2,422	(4,589)
Purchase of furniture and equipment	(300)	(484)
Net cash used in investing activities	(134,747)	(104,091)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	58,000	19,000
Repayment of revolving credit facility	(58,000)	(117,000)
Proceeds from issuance of senior secured notes, net of discount	—	194,500
Proceeds from issuance of common stock, net of issuance costs	101,513	—
Repurchase of outstanding common stock	—	(9,753)
Proceeds from issuance of preferred stock, net of issuance costs	2,064	133
Dividends on preferred stock	(10,805)	(6,398)
Deferred financing charges	(405)	(2,807)
Tax withholding related to restricted stock and PBU vestings	(3,709)	(349)
Other	13	—
Net cash provided by financing activities	88,671	77,326
NET INCREASE IN CASH AND CASH EQUIVALENTS	14,205	12,474
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	32,393	8,901
CASH AND CASH EQUIVALENTS, END OF PERIOD	$46,598	$21,375

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

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

1. Description of Business

Gastar Exploration Inc. (the "Company" or "Gastar," and before January 31, 2014, "Gastar USA") is an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Gastar Exploration Inc.'s principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. 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 Mid-Continent 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.

On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation ("Parent"), 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 USA and Gastar USA changed its name to "Gastar Exploration Inc." Gastar Exploration Inc., together with its subsidiary, owns and will continue to conduct business in substantially the same manner as was being conducted by Gastar Exploration, Inc. and its subsidiaries prior to the merger.

2. Summary of Significant Accounting Policies

The accounting policies followed by the Company are set forth in the notes to the Company's audited consolidated financial statements included in its Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 Form 10-K") filed with the SEC. Please refer to the notes to the consolidated financial statements included in the 2013 Form 10-K for additional details of the Company's financial condition, results of operations and cash flows. No material item included in those notes has changed except as a result of normal transactions in the interim or as disclosed within this report.

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

The unaudited interim condensed consolidated financial statements of the Company included herein are stated in U.S. dollars and were prepared from the records of the Company by management in accordance with U.S. GAAP applicable to interim financial statements and reflect all normal and recurring adjustments, which are, in the opinion of management, necessary to provide a fair presentation of the results of operations and financial position for the interim periods. Such financial statements conform to the presentation reflected in the 2013 Form 10-K. The current interim period reported herein should be read in conjunction with the financial statements and accompanying notes, including Item 8. "Financial Statements and Supplementary Data, Note 2 – Summary of Significant Accounting Policies," included in the 2013 Form 10-K.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows.

The unaudited interim condensed consolidated financial statements of the Company include the consolidated accounts of all of its subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

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

The results of operations for the three and nine months ended September 30, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014. In preparing these financial statements, the Company has evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued and has disclosed certain subsequent events in these condensed consolidated financial statements, as appropriate.

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Recent Accounting Developments

The following recently issued accounting pronouncement 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 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 a 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.

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 East Texas assets on October 2, 2013, with an effective date of January 1, 2013.

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

	September 30, 2014	December 31, 2013
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$18,566	$4,774
Acreage acquisition costs	93,528	86,097
Capitalized interest	7,274	5,349
Total unproved properties excluded from amortization	$119,368	$96,220

For the three and nine months ended September 30, 2014, 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 $2.7 million and $3.2 million of unproved properties to proved properties for the three and nine months ended September 30, 2014, respectively, related to acreage in Marcellus East. For the three and nine months ended September 30, 2013, management's evaluation of unproved properties resulted in an impairment and $98,000 and $8.0 million of unproved property costs were reclassified to proved property costs, respectively, related to acreage in Marcellus East.

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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 the Company's 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 with respect to valuing future net cash flows from proved reserves for this purpose. 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 pricing assumptions utilized in the quarterly ceiling test computations for the respective periods noted before adjustment for basis and quality differentials:

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

	2013			
	Total Impairment	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$3.60	$3.44	$2.95
West Texas Intermediate oil price (per Bbl)(1)		$95.04	$91.60	$92.63
Impairment recorded (pre-tax) (in thousands)	$—	$—	$—	$—

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

Future declines in the 12-month average of oil, condensate, natural gas and NGLs prices could result in the recognition of future ceiling impairments.

Chesapeake Acquisition

On June 7, 2013, Gastar USA acquired from Chesapeake Exploration, L.L.C. and Larchmont Resources, L.L.C. (together, the “Chesapeake Parties”) approximately 157,000 net acres of Oklahoma oil and gas leasehold interests, including production from interests in 206 producing wells located in Oklahoma (the “Chesapeake Assets”) for a final adjusted purchase price of $69.4 million, reflecting adjustment for an acquisition effective date of October 1, 2012 (the “Chesapeake Acquisition”). The Company accounted for the Chesapeake 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 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 were unobservable and, as such, represented Level 3 inputs under the fair value hierarchy as described in Note 5, “Fair Value Measurements.” The Company's assessment of the fair value of the Chesapeake Assets resulted in a fair market valuation of $113.1 million. Upon completion of the preliminary asset valuation, the Company recorded a bargain purchase gain of $43.7 million during the second quarter of 2013. With the completion of the asset valuation during the fourth quarter of 2013, the Company recorded deferred tax attributes associated with the transaction of $16.0 million. As a result of incorporating the final valuation information into the purchase price allocation, a net bargain purchase gain of $27.7 million was recognized in 2013 with respect to the Chesapeake Acquisition.

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Hunton Joint Venture and 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 August 6, 2013, Gastar USA sold approximately 76,000 net acres of oil and gas leasehold interests in Kingfisher and Canadian Counties, Oklahoma to Newfield Exploration Mid-Continent Inc. (“Newfield”) and Gastar USA acquired approximately 1,850 net acres of Oklahoma oil and gas leasehold interests from Newfield for a net cash purchase price of approximately $57.0 million, adjusted for an 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 November 15, 2013, 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 from Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. (the “Lime Rock Parties”) for an adjusted cash purchase price of $177.8 million, reflecting customary adjustments and adjustment for an acquisition effective date of August 1, 2013 (the “WEHLU Acquisition”). The Company accounted for the WEHLU 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 were unobservable and, as such, represent Level 3 inputs under the fair value hierarchy as described in Note 5, “Fair Value Measurements.” The Company's 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.

Chesapeake and WEHLU Acquisitions Pro Forma Operating Results

The following unaudited pro forma results for the three and nine months ended September 30, 2013 show the effect on the Company's consolidated results of operations as if the Chesapeake and WEHLU Acquisitions had occurred on January 1, 2013. Pro forma results are not presented for the three and nine months ended September 30, 2014, as the results of operations for the acquisitions are included in the Company's results of operations for those periods. The pro forma results for the three and nine months ended September 30, 2013 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 Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2013
	(in thousands, except per share data) (Unaudited)	
Revenues	$31,623	$100,374
Net Income	$(3,288)	$(3,148)

Income per share:		
Basic	$(0.06)	$(0.05)
Diluted	$(0.06)	$(0.05)

The pro forma information above includes numerous assumptions, is presented for illustrative purposes only, and may not be indicative of the future results or results of operations that would have actually occurred had the Chesapeake and WEHLU Acquisitions occurred as presented. Further, the above pro forma amounts do not consider any potential synergies or

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integration costs that may result from the transaction. In addition, future results may vary significantly from the results reflected in such pro forma information.

Hilltop Area, East Texas Sale

On October 2, 2013, Gastar Exploration Texas, LP ("Gastar Texas") and Gastar USA sold to Cubic Energy, Inc. ("Cubic Energy") approximately 31,800 gross (16,300 net) acres of leasehold interests in the Hilltop area of East Texas in Leon and Robertson Counties, Texas, including production from interests in producing wells, for net proceeds of approximately $42.9 million, reflecting adjustment for an effective date of January 1, 2013 and other customary adjustments. The Company did not record a gain or loss related to the divestiture as it was not significant to the full cost pool.

Atinum Joint Venture

In September 2010, Gastar USA entered into a joint venture (the "Atinum Joint Venture") pursuant to which Gastar USA ultimately assigned to an affiliate of Atinum Partners Co., Ltd. ("Atinum"), for total consideration of $70.0 million, a 50% working interest in certain undeveloped acreage and wells. Effective 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 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 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, Atinum and Gastar USA agreed to reduce the minimum wells to be drilled requirements by nine wells to 51 wells from 60 wells. At September 30, 2014, 57 gross operated horizontal Marcellus Shale wells and one gross operated horizontal Utica Shale well were capable of production under the Atinum Joint Venture.

4. Long-Term Debt

Second Amended and Restated Revolving Credit Facility

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

The Revolving Credit Facility is guaranteed by all of the Company's current domestic subsidiaries and all future domestic subsidiaries formed during the term of the Revolving Credit Facility, in each case with the exception of those subsidiaries the Company has chosen to exclude that are deemed immaterial. Borrowings and related guarantees are secured by a first priority lien on all domestic oil and natural gas 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 each 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 net indebtedness to EBITDA of not greater than 4.0 to 1.0; and
- Maintenance of an interest coverage ratio on a rolling four quarters basis, as adjusted, of EBITDA to interest expense, as of the end of each quarter, to be less than 2.5 to 1.0.

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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 under the Revolving Credit Facility.

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

On October 18, 2013, Gastar USA, together with the parties thereto, entered into the Agreement and Amendment No. 2 ("Amendment No. 2") to Second Amended and Restated Credit Agreement, dated as of June 7, 2013. Amendment No. 2 amended the Revolving Credit Facility to, among other things, (i) increase the aggregate principal amount of 8 5/8% Senior Secured Notes due 2018 permitted to be issued from $200.0 million to $325.0 million, (ii) allow for the issuance by Gastar USA of Series B Preferred Stock and (iii) increase the aggregate amount of cash dividends permitted to be paid to preferred stockholders from $12.5 million to $20.0 million.

On December 9, 2013, the borrowing base under the Revolving Credit Facility was increased by the lending participants to $100.0 million.

On March 12, 2014, the Company, together with the parties thereto, entered into the Agreement, Waiver and Amendment No. 3 ("Amendment No. 3") to Second Amended and Restated Credit Agreement, dated as of June 7, 2013. Amendment No. 3 amended the Revolving Credit Facility to, among other things, (i) permit the Company to exclude current and future subsidiaries that are deemed to be immaterial from becoming guarantors of the Revolving Credit Facility, provided such non-guarantor subsidiaries comply with certain restrictions, (ii) exclude the non-guarantor subsidiaries from the provisions of the negative covenants of the Revolving Credit Facility with respect to mergers and acquisitions, restricted payments and investments and (iii) exclude the non-guarantor subsidiaries from being included in the calculation of the borrowing base under the Revolving Credit Facility.

On March 26, 2014, the borrowing base under the Revolving Credit Facility was increased by the lending participants to $120.0 million.

On August 13, 2014, the Company, together with the parties thereto, entered into a Master Assignment, Agreement, and Amendment No. 4 ("Amendment No. 4") to Second Amended and Restated Credit Agreement, dated as of June 7, 2013. Amendment No. 4 amended the Revolving Credit Facility to, among other things, increase the borrowing base from $120.0 million to $145.0 million.

Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. The Company and its lenders may request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. At September 30, 2014, the Revolving Credit Facility had a borrowing base of $145.0 million, with $0 borrowings outstanding and availability of $145.0 million. The next regularly scheduled redetermination is set for May 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 September 30, 2014, the Company was in compliance with all financial covenants under the Revolving Credit Facility.

Amended and Restated Revolving Credit Facility

For the period October 28, 2009 through June 6, 2013, Gastar USA, together with the other parties thereto, was subject to an amended and restated credit facility (the "Prior Amended Revolving Credit Facility"). The Prior Amended Revolving Credit Facility provided for various borrowing base amounts based on an initial borrowing base of $47.5 million and a final borrowing base of $160.0 million effective March 31, 2013. Borrowings bore interest, at Gastar USA's election, at the prime rate or LIBO rate plus an applicable margin. The applicable interest rate margin varied from 1.0% to 2.0% in the case of borrowings based on the prime rate and from 2.5% to 3.5% in the case of borrowings based on LIBO rate, depending on the utilization percentage in relation to the borrowing base. An annual commitment fee of 0.5% was payable quarterly based on the unutilized balance of the borrowing base. The Prior Amended Revolving Credit Facility had a final scheduled maturity date of September 30, 2015. The Prior Amended Revolving

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

Senior Secured Notes

On May 15, 2013, Gastar USA issued $200.0 million aggregate principal amount of its 8 5/8% Senior Secured Notes due May 15, 2018 under an indenture (the “Indenture”) by and among Gastar USA, the Guarantors named therein (the “Guarantors”), Wells Fargo Bank, National Association, as Trustee (in such capacity, the “Trustee”) and Collateral Agent (in

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such capacity, the “Collateral Agent”). On November 15, 2013, Gastar USA issued an additional $125.0 million aggregate principal amount of additional notes under the Indenture. The 8 5/8% Senior Secured Notes due 2018 are collectively referred to as the “Notes.” The Notes bear interest at a rate of 8.625% per year, payable semiannually in arrears on May 15 and November 15 of each year, beginning on November 15, 2013. The Notes will mature on May 15, 2018. Gastar USA received net proceeds of approximately $312.3 million, net of debt issuance costs and any original issue discounts.

In the event of a change of control, as defined in the Indenture, each holder of the Notes will have the right to require 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 are fully and unconditionally guaranteed, jointly and severally, on a senior secured basis by each of the Company's material subsidiaries and certain future domestic subsidiaries (the “Guarantees”). The Notes and Guarantees 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 are effectively senior to the Company's unsecured indebtedness and effectively subordinated to the Company's and Guarantors' 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, consolidate 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.

In May 2014, holders of the 8 5/8% Senior Secured Notes due 2018 exchanged their notes for registered notes with the same terms.

At September 30, 2014, the Notes reflected a balance of $314.7 million, net of unamortized discounts of $10.3 million, on the condensed consolidated balance sheets.

5. Fair Value Measurements

The Company’s financial assets and liabilities are measured at fair value on a recurring basis. The Company discloses its recognized non-financial assets and liabilities, such as asset retirement obligations, unproved properties and other property and 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 or estimated market data based on area transactions, which are Level 3 inputs. For the three and nine months ended September 30, 2014, 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 $2.7 million and $3.2 million of unproved properties to proved properties for the three and nine months ended September 30, 2014, respectively, related to acreage in Marcellus East. For the three and nine months ended September 30, 2013, management's evaluation of unproved properties resulted in an impairment of $98,000 and $8.0 million, respectively, related to Marcellus East. As no other fair value measurements are required to be recognized on a non-recurring basis at September 30, 2014, no additional disclosures are provided at September 30, 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

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utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ("Level 1") and the lowest priority to unobservable inputs ("Level 3"). The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities. The Company's cash equivalents consist of short-term, highly liquid investments, which have maturities of 90 days or less, including sweep investments and money market funds.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources. These inputs may be used with internally developed methodologies or third party broker quotes that result in management's best estimate of fair value. The Company's valuation models consider various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Level 3 instruments are commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge natural gas, oil and NGLs price risk. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs. The fair values derived from counterparties and third-party brokers are verified by the Company using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its 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.

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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 September 30, 2014 and December 31, 2013:

	Fair value as of September 30, 2014			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$46,598	$—	$—	$46,598
Commodity derivative contracts	—	—	4,179	4,179
Liabilities:				
Commodity derivative contracts	—	—	(1,301)	(1,301)
Total	$46,598	$—	$2,878	$49,476

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

The table below presents a reconciliation of the assets and liabilities classified as Level 3 in the fair value hierarchy for the three and nine months ended September 30, 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 September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Balance at beginning of period	$(4,628)	$4,335	$3,764	$6,465
Total gains (losses) included in earnings	6,663	(5,263)	(8,761)	(2,229)
Purchases	30	9,545	369	9,572
Issuances	—	—	—	—
Settlements (1)	813	247	7,506	(4,944)
Transfers in and (out) of Level 3	—	—	—	—
Balance at end of period	$2,878	$8,864	$2,878	$8,864
The amount of total gains (losses) for the period included in earnings attributable to the change in mark to market of commodity derivatives contracts still held at September 30, 2014 and 2013	$7,623	$5,004	$(950)	$(7,156)

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

At September 30, 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 September 30, 2014 was $337.2 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 6, "Derivative Instruments and Hedging Activity."

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6. Derivative Instruments and Hedging Activity

The Company maintains a commodity price risk management strategy that uses derivative instruments to minimize significant, unanticipated earnings fluctuations that may arise from volatility in commodity prices. The Company uses costless collars, index, basis and fixed price swaps and put and call options to hedge 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 condensed consolidated statements of operations in (loss) gain on commodity derivatives contracts. For the three months ended September 30, 2014 and 2013, the Company reported a gain of $6.7 million and a loss of $5.3 million, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts. For the nine months ended September 30, 2014 and 2013, the Company reported losses of $8.8 million and $2.2 million, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts.

As of September 30, 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 MMBtus)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Call (Long)	Ceiling (Short)
2014	Fixed price swap	8,663	797,000	$4.06	$—	$—	$—	$—
2014	Fixed price swap	2,000	184,000	$3.72	$—	$—	$—	$—
2014	Fixed price swap	2,000	184,000	$3.98	$—	$—	$—	$—
2014	Fixed price swap	2,000	184,000	$4.07	$—	$—	$—	$—
2014	Fixed price swap	1,871	172,100	$4.32	$—	$—	$—	$—
2014	Short calls	2,000	184,000	$—	$—	$—	$—	$4.59
2014	Costless collar	3,000	276,000	$—	$4.00	$—	$—	$4.36
2014	Costless collar	5,000	460,000	$—	$4.00	$—	$—	$4.55
2014	Costless collar	2,500	230,000	$—	$4.00	$—	$—	$5.00
2014	Put spread	2,000	184,000	$—	$4.00	$3.72	$—	$—
2014	Basis swap (1)	2,500	230,000	$(1.39)	$—	$—	$—	$—
2014	Basis swap (1)	2,500	230,000	$(1.32)	$—	$—	$—	$—
2015 (2)	Protective spread	10,000	900,000	$4.46	$—	$3.70	$—	$—
2015 (2)	Call spread	10,000	900,000	$—	$—	$—	$4.46	$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 (2)	Producer three-way collar	3,750	337,500	$—	$4.60	$3.50	$—	$5.34
2015	Producer three-way collar	2,000	760,000	$—	$4.00	$3.25	$—	$4.58
2015	Basis swap (1)	2,500	912,500	$(1.12)	$—	$—	$—	$—
2015	Basis swap (1)	2,500	912,500	$(1.11)	$—	$—	$—	$—
2015 (3)	Producer three-way collar	5,000	1,375,000	$—	$4.00	$3.25	$—	$5.00
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) Represents basis swaps at the sales point of Dominion South

(2) For the period January to March 2015.

(3) For the period April to December 2015.

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As of September 30, 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)
2014	Fixed price swap	750	69,000	$90.35	$—	$—	$—
2014	Fixed price swap	200	18,400	$93.00	$—	$—	$—
2014	Fixed price swap	350	32,200	$91.55	$—	$—	$—
2014	Fixed price swap	500	46,000	$91.10	$—	$—	$—
2014	Fixed price swap	250	23,000	$90.77	$—	$—	$—
2014	Costless collar	200	18,400	$—	$98.00	$—	$98.00
2014	Put spread	200	18,400	$—	$93.00	$73.00	$—
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 September 30, 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
2014	Fixed price swap	250	23,000	$46.10
2014	Fixed price swap	250	23,000	$48.11
2015 (1)	Fixed price swap	250	68,750	$45.61

(1) For the period April to December 2015.

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As of September 30, 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 contain credit-risk related contingent features.

In conjunction with certain derivative hedging activity, the Company deferred the payment of certain put premiums for the production month period December 2013 through August 2018. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company began amortizing the deferred put premium liabilities in December 2013. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

	September 30, 2014	December 31, 2013
	(in thousands)	
Current commodity derivative premium put payable	$1,966	$145
Long-term commodity derivative premium payable	5,327	7,000
Total unamortized put premium liabilities	$7,293	$7,145

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of September 30, 2014:

	Amortization
	(in thousands)
October to December 2014	$109
January to December 2015	2,482
January to December 2016	2,408
January to December 2017	1,460
January to August 2018	834
Total unamortized put premium liabilities	$7,293

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Additional Disclosures about Derivative Instruments and Hedging Activities

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

	Fair Values of Derivative Instruments Derivative Assets (Liabilities)		
	Balance Sheet Location	Fair Value September 30, 2014	December 31, 2013
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$2,735	$—
Commodity derivative contracts	Other assets	1,444	7,545
Commodity derivative contracts	Current liabilities	(419)	(3,403)
Commodity derivative contracts	Long-term liabilities	(882)	(378)
Total derivatives not designated as hedging instruments		$2,878	$3,764

	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Amount of Gain (Loss) Recognized in Income on Derivatives For the Three Months Ended September 30,	
	Location of Gain (Loss) Recognized in Income on Derivatives	2014	2013
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Gain (loss) on commodity derivatives contracts	$6,663	$(5,263)
Total		$6,663	$(5,263)

	Amount of Loss Recognized in Income on Derivatives		
		Amount of Loss Recognized in Income on Derivatives For the Nine Months Ended September 30,	
	Location of Loss Recognized in Income on Derivatives	2014	2013
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Loss on commodity derivatives contracts	$(8,761)	$(2,229)
Total		$(8,761)	$(2,229)

7. Capital Stock

Common Stock

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

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

Prior to its conversion, as described below, Gastar USA's articles of incorporation allowed Gastar USA to issue 1,000 shares of common stock, without par value. There were 750 shares issued and outstanding at December 31, 2013, all of which were held by Parent.

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

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 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.

Other Share Issuances

The following table provides information regarding the issuances and forfeitures of common stock pursuant to the Company's long-term incentive plan for the periods indicated:

	For the Three Months Ended September 30, 2014	For the Nine Months Ended September 30, 2014
Other share issuances:		
Restricted common shares granted	67,633	601,473
Restricted common shares vested	22,737	1,215,533
Common shares surrendered upon vesting (1)	7,967	407,733
Common shares issued upon vesting of PBUs, net of shares surrendered for taxes	—	472,189
Stock options exercised	7,500	7,500
Common shares issued upon exercise of stock options, net of shares surrendered for taxes	6,717	6,717
Common shares forfeited	241	22,139

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

On June 12, 2014, the Company's stockholders approved an amendment and restatement to the Gastar Exploration Inc. Long-Term Incentive Plan (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 4,332,153 shares available for issuance under the LTIP at September 30, 2014.

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Shares Reserved
At September 30, 2014, the Company had 866,600 common shares reserved for the exercise of stock options.
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 Exploration Texas, LP and Gastar Exploration 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 Energy Corporation upon the closing of the stock repurchase and settlement on June 7, 2013.
Preferred Stock
Prior to the Conversion, Gastar USA's articles of incorporation did not authorize issuance of preferred stock. Following the Conversion, Gastar USA's new Delaware certificate of incorporation allows Gastar USA to issue 10,000,000 shares of preferred stock, with $0.01 par value (the "Preferred Stock"). The Preferred Stock was permitted to be issued from time to time in one or more series. Gastar USA's Board of Directors (the "Gastar USA Board") was authorized to fix the number of shares of any series of Preferred Stock and to determine the designation of any such series. The Gastar USA Board was also authorized to determine or alter the rights, preferences, privileges and restrictions granted to or imposed upon any wholly unissued series of Preferred Stock and, within the limits and restrictions stated in any resolution or resolutions of the Gastar USA Board originally fixing the number of shares constituting any series, to increase or decrease (but not below the number of shares of any such series outstanding) the number of shares of any series subsequent to the issues shares of that series). Pursuant to the A&R Certificate, the number of shares of Preferred Stock authorized for issuance was increased to 40,000,000 shares.
Series A Preferred Stock
For the nine months ended September 30, 2014, the Company sold 86,840 shares of its 8.625% Series A Preferred Stock, par value $0.01 per share and liquidation preference $25.00 per share (the "Series A Preferred Stock"), under its at the market preferred share purchase agreement (the "ATM Agreement") for net proceeds of $2.1 million. At September 30, 2014, there were 4,045,000 total shares of Series A Preferred Stock issued and outstanding.
The Series A Preferred Stock is subordinated to all of the Company'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, but may be redeemed, at the Company's option for $25.00 per share plus any accrued and unpaid dividends.
There is no mandatory redemption of the Series A Preferred Stock.
The Company 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 three and nine months ended September 30, 2014, the Company recognized dividend expense of $2.2 million and $6.5 million, respectively, for the Series A Preferred Stock.
Series B Preferred Stock
On October 29, 2013, the Company sold 2,000,000 shares of 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. Net proceeds from the sale of the Series B Preferred Stock were approximately $50.1 million after deducting underwriting commissions and offering expenses.
The Series B Preferred Stock ranks senior to the Company's common stock and on parity with the Series A 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 the Company'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 the Company’s option for $25.00 per share in cash. Following a change in

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ownership or control, the Company 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 the Company 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 an aggregate of 11.5207 shares of the Company's common stock per share of Series B Preferred Stock, subject to certain adjustments. If the Company 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.
The Company 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 three and nine months ended September 30, 2014, the Company recognized dividend expense of $1.4 million and $4.3 million, respectively, for the Series B Preferred Stock.

8. Equity Compensation Plans

Share-Based Compensation Plan

Pursuant to the LTIP, the Company's Compensation Committee agreed to allocate a portion of the 2013 and 2014 long-term incentive grants to executives as performance based units ("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 number of PBUs 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 (1)	(355,247)	1.56
Forfeited	—	—
Unvested PBUs at September 30, 2014	990,658	$3.19

(1) The first tranche of the January 30, 2013 PBU grant vested on January 30, 2014 and settled at 200% based on the Company's share price appreciation compared to the peer group index.

For the three and nine months ended September 30, 2014, the Company recognized $430,000 and $1.2 million, respectively, of compensation expense associated with the PBUs granted on January 30, 2013 and 2014.

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9. Interest Expense

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Interest expense:				
Cash and accrued	$7,297	$4,376	$21,639	$8,238
Amortization of deferred financing costs (1)	779	340	2,270	1,790
Capitalized interest	(1,085)	(1,277)	(3,115)	(2,435)
Total interest expense	$6,991	$3,439	$20,794	$7,593

(1) The three and nine months ended September 30, 2014 includes $584,000 and $1.7 million, respectively, of debt discount accretion related to the Notes.

10. Income Taxes

For the three and nine months ended September 30, 2014 and 2013, respectively, the Company did not recognize a current income tax benefit or provision due to the Company being in a net operating loss position for both periods.

11. Earnings per Share

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands, except per share and share data)			
Net income (loss) attributable to common stockholders	$9,807	$(3,942)	$9,858	$43,308
Weighted average common shares outstanding - basic	60,006,903	57,359,357	58,982,709	61,159,117
Incremental shares from unvested restricted shares	2,614,215	—	2,587,345	2,565,888
Incremental shares from outstanding stock options	115,421	—	109,755	—
Incremental shares from outstanding PBUs	662,907	—	626,671	246,033
Weighted average common shares outstanding - diluted	63,399,446	57,359,357	62,306,480	63,971,038
Net income (loss) per share of common stock attributable to common stockholders:				
Basic	$0.16	$(0.07)	$0.17	$0.71
Diluted	$0.15	$(0.07)	$0.16	$0.68
Common shares excluded from denominator as anti-dilutive:				
Unvested restricted shares	14,877	—	45,203	41,212
Stock options	—	756,200	—	919,100
Unvested PBUs	—	—	—	—
Total	14,877	756,200	45,203	960,312

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12. Commitments and Contingencies

Litigation

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 alleged that Williams OVM had 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, maximize the net value of the condensate, and NGLs as provided in the agreements. On August 7, 2013, Williams OVM filed an answering statement and counterclaim for damages in excess of $612,000 in the arbitration matter. On December 31, 2013, the parties informed the Arbitration Panel that they 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 is $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 sought discretionary review from the Texas Supreme Court, and their petition for review was filed on February 18, 2014. At the request of the Texas Supreme Court, the Company filed a response to the insurers petition on June 25, 2014. The Court has neither granted or denied the petition, but has nevertheless asked for briefing on the merits. The petitioners' brief was filed on October 22, 2014. The Company's response was due on November 1, 2014, but the Company requested an extension. The motion for the extension was granted and the response brief is now due on December 12, 2014. The petitioners will have ten days to file a reply. If the Court denies review or affirms the Fourteenth Court of Appeals' ruling, the case will be remanded to the District Court. The District Court proceedings will include, but not be limited to, a determination of whether the Company's claims are securities claims covered by the insuring agreements.

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. Gastar has drilled and completed 15 gross horizontal wells on this lease without any apparent incident or interference with Eagle's facilities. 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 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 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. The Court set a hearing for a preliminary injunction on November 12, 2014. Gastar intends to vigorously defend these claims and will have a variety of defenses available to it.

The Company has been expensing legal 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

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these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, management does not believe any such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

13. Statement of Cash Flows – Supplemental Information

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

	For the Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Cash paid for interest, net of capitalized amounts	$11,668	$—
Non-cash transactions:		
Capital expenditures included in (excluded from) accounts payable and accrued drilling costs	1,601	(8,335)
Capital expenditures included in accounts receivable	4,077	—
Asset retirement obligation included in oil and natural gas properties	109	1,795
Asset retirement obligation assigned to operator	—	(362)
Application of advances to operators	36,812	14,443
Expenses accrued for the issuance of common stock	223	—
Other	(11)	61

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking information that is intended to be covered by the “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (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 report are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “t the negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations and beliefs concerning future developments and their potential effect on us, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Forward-looking statements may include statements that relate to, among other things, our:

- financial position;
- business strategy and budgets;
- anticipated capital expenditures;
- drilling of wells, including the anticipated scheduling and results of such operations;
- oil, natural gas NGLs reserves;
- timing and amount of future production of oil, condensate, natural gas and NGLs;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development; and
- property acquisitions and sales.

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

- the extent to which we are able to realize the anticipated benefits from acquired assets;
- the supply and demand for oil, condensate, natural gas and NGLs;
- low and/or declining prices for oil, condensate, natural gas and NGLs;
- price volatility of oil, condensate, natural gas and NGLs;
- worldwide political and economic conditions and conditions in the energy market;
- our ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or fulfill their obligation to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the ability to find, acquire, market, develop and produce new oil and natural gas properties;
- 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;

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- availability and cost of processing and transportation;
- changes or advances in technology;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry wells, operating hazards inherent to the natural gas and oil business and down hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells or pipeline mishaps;
- environmental risks;
- possible new legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, national healthcare, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, environmental risks and liability under federal, state and local environmental laws and regulations;
- effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;
- potential losses from pending or possible future claims, litigation or enforcement actions;
- potential defects in title to our properties or lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;
- the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;
- 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.

For a more detailed description of the risks and uncertainties that we face and other factors that could affect our financial performance or cause our actual results to differ materially from our projected results please see (i) Part II, Item 1A. “Risk Factors” and elsewhere in this report and our prior reports on Form 10-Q for this year, (ii) Part I, Item 1A. “Risk Factors” and elsewhere in our 2013 Form 10-K, (iii) our subsequent reports and registration statements filed from time to time with the SEC and (iv) other announcements we make from time to time.

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

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

Overview

We are an independent energy company engaged in the exploration, development and production of 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 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 Mid-Continent 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 on October 2, 2013, with an effective date of January 1, 2013.

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

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under the symbol "GST." Shares of Gastar Exploration Inc.'s 8.625% Series A Cumulative Preferred Stock (symbol "GST.PRA") and its 10.75% Series B Cumulative Preferred Stock (symbol "GST.PRB") are also listed on the NYSE MKT LLC.

Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. As of September 30, 2014, our major assets consist of approximately 246,800 gross (127,700 net) acres in Oklahoma and approximately 74,600 gross (51,800 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania, of which approximately 28,400 gross (12,000 net) acres have Utica Shale potential, of which approximately 4,500 gross (2,000 net) acres are pending lease finalization.

The following discussion addresses material changes in our results of operations for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 and material changes in our financial condition since December 31, 2013. This discussion should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in Part I, Item 1. "Financial Statements" of this report, as well as our 2013 Form 10-K, which includes important disclosures regarding our critical accounting policies as part of Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Oil and Natural Gas Activities

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

Mid-Continent Horizontal Oil Play. The Hunton Limestone is a limestone formation stretching over approximately 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. At September 30, 2014, we held leases covering approximately 246,800 gross (127,700 net) acres in Major, Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the Hunton Limestone horizontal oil play.

Our leasing activities are continuing in the initial AMI prospect area with our joint venture operator and two additional adjacent prospect areas. For the first 12,500 gross acres acquired in the initial AMI prospect, we paid 62.5% of the lease acquisition costs for a 50% leasehold interest and 50% of the lease acquisition costs on additional acres in excess of 12,500 gross acres acquired for a 50% working interest. We will pay 54.25% of the lease acquisition costs in the two new prospect areas for a 50% working interest. In the initial prospect area, we pay 62.5% of the first four wells' gross drilling and completion costs and 56.25% of the next four wells' gross drilling and completion costs to earn a 50% working interest. For all additional wells beyond the first eight in the initial prospect area, we are responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). In all subsequent prospect areas, we pay 54.25% of gross drilling and completion costs on all wells drilled in the additional prospect to earn a 50% working interest. Our AMI joint venture operator handles all drilling, completion and production activities, and we handle all leasing activities in two of the three AMI prospect areas. We expect to continue to consolidate our acreage position in this region during the fourth quarter of 2014, both inside and outside of the AMI.

On June 7, 2013, we acquired approximately 157,000 net acres of Oklahoma oil and gas leasehold interests in Canadian and Kingfisher Counties, Oklahoma from the Chesapeake Parties, including production from interests in 206 producing wells, for an adjusted cash purchase price of approximately $69.4 million (reflecting adjustment for an acquisition effective date of October 1, 2012). Effective July 1, 2013, our joint venture operator in our original AMI in Oklahoma exercised its rights to acquire approximately 12,800 net acres and certain proved properties that we acquired from the Chesapeake Parties for a total payment of $11.6 million (reflecting adjustment for an acquisition effective date of October 1, 2012). In addition, on August 6, 2013, we sold approximately 76,000 net acres in Kingfisher and Canadian Counties, Oklahoma to Newfield 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 WEHLU located in Kingfisher, Logan and Oklahoma Counties, Oklahoma, including production from interests in 56 gross (55.0 net) producing wells, for an adjusted cash purchase price of approximately $177.8 million (reflecting adjustment for an acquisition effective date of August 1, 2013).

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As of September 30, 2014 and currently as of the date of this report, we had initial production and drilling operations at various stages on the following wells in our original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	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)
Jett 1-12H	47.4%	3,900	408	216	80%	February 1, 2014	$6.9
Jones 1-21H	48.4%	4,200	449	214	56%	March 2, 2014	$5.6
Liebhart 1-31H	48.8%	4,400	146	90	78%	March 18, 2014	$6.4
Coronado 1-3H	43.6%	4,300	224	148	73%	March 19, 2014	$5.3
Gamebird 1-7H	48.4%	4,400	764	472	83%	April 2, 2014	$5.5
Sieber 1-31H	33.7%	4,400	1,013	701	68%	April 13, 2014	$5.2
Kodiak 1-29H	45.3%	4,300	1,666	899	77%	May 4, 2014	$4.5
Anna Lee 1-30H	50.0%	4,400	220	110	65%	May 20, 2014	$5.1
Vaverka 1-20H	46.9%	4,400	N/A	192	68%	July 10, 2014	$5.7
Sasquatch 1-23H	44.2%	4,800	581	372	66%	July 27, 2014	$5.6
Jam 1-4H	36.8%	4,900	477	348	57%	August 8, 2014	$5.9
Yeti 1-29H	32.8%	5,000	1,015	687	57%	August 26, 2014	$6.0
Danny Ray 1-30H	31.7%	5,000	N/A	312	71%	August 29, 2014	$6.0
Cline 1-13H	50.0%	5,100	N/A	85	88%	September 6, 2014	$6.1
Michael J 1-18H	33.3%	5,000	N/A	362	80%	September 29, 2014	$6.0
Shimanek 1-2H	48.9%	5,000	1,829	1,756	79%	October 9, 2014	$6.0
Hobbs Ranch 1-19H	29.5%	4,400	N/A	573	84%	October 13, 2014	$5.7
Snowman 1-19H	36.1%	4,900	N/A	N/A	N/A	Awaiting completion	$5.9
Breckenridge 1-2H	25.4%	4,800	N/A	N/A	N/A	Awaiting completion	$5.8
Polar Bear 1-20H	45.6%	4,400	N/A	N/A	N/A	Awaiting completion	$5.7
Joyce 1-10H[3]	51.7%	5,300	N/A	N/A	N/A	Awaiting completion	$6.3
Falcon 1-5H	38.5%	4,700	N/A	N/A	N/A	Awaiting completion	$5.8
Bear Claw 1-28H	38.3%	5,000	N/A	N/A	N/A	Awaiting completion	$6.0
Barry 1-6H	42.6%	5,000	N/A	N/A	N/A	Awaiting completion	$6.0
The River 1-22H	28.3%	4,400	N/A	N/A	N/A	Drilling	$5.7
Boss Hogg 1-14H	43.8%	4,400	N/A	N/A	N/A	Drilling	$5.7
Hubbard 1-23H[4]	57.0%	4,600	N/A	N/A	N/A	Drilling	$5.8

(1) Represents highest daily gross BOE rate.
(2) Represents gross average production for actual producing days through October 30, 2014.
(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 September 30, 2014 and currently as of the date of this report, we had initial production and drilling operations at various stages on the following non-operated wells outside the 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	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	241	59%	February 1, 2014	$5.4
Grizzly 1-4H	8.8%	3,600	387	218	56%	May 1, 2014	$4.9
Niemyer 1-2H	15.9%	5,000	422	299	59%	June 24, 2014	$5.5
Wolf 1-9H	16.0%	3,600	N/A	N/A	N/A	Awaiting completion	$4.6

(1) Represents highest daily gross BOE rate.

(2) Represents gross average production for actual producing dates through October 30, 2014.

As of September 30, 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 lower 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	144	39%	March 6, 2014	$10.0
Easton 22-1H	98.3%	4,900	673	433	90%	July 30, 2014	$7.5
Easton 22-2H	98.3%	6,500	855	463	93%	August 5, 2014	$3.9
Horseshoe 3-1H	99.3%	5,100	N/A	263	49%	September 16, 2014	$6.2
Deer Draw 21-4H	98.3%	5,900	N/A	N/A	N/A	Awaiting completion	$4.3
Deer Draw 21-5H	98.3%	4,900	N/A	N/A	N/A	Awaiting completion	$5.5
Warsaw 33-1[3]	98.3%	N/A	N/A	N/A	N/A	Drilling	$3.0

(1) Represents highest daily gross BOE rate.

(2) Represents gross average production for actual producing dates through October 30, 2014.

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

The Easton 22-1H well is a lower Hunton Limestone horizontal completion, while the Easton 22-2H is an upper Hunton Limestone horizontal completion. The Deer Draw 21-4H and 21-5H are lower Hunton Limestone horizontal completions and are estimated to commence flow back operations by mid-November 2014. The Easton and Deer Draw wells are located within our WEHLU acreage. The Horseshoe 3-1H is a lower Hunton Limestone horizontal completion located in Canadian County, Oklahoma.

We continue to target our horizontal laterals in the Hunton Limestone formation and increase the number of fracturing stages 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 overall well results to date.

We have also participated in 3.0 gross (0.9 net) wells outside of our AMI acreage targeting the Hunton Limestone, the Woodford Shale and the Mississippi Lime formations. The non-operated Woodford Shale well is still awaiting completion. In addition, we recently assigned approximately 9,600 gross (4,200 net) acres within certain townships in Kingfisher County, on a “checkerboard” (every other section) basis, for approximately $800 per net acre. A portion of the acreage will be reassigned to us in the future if the acreage is not held by production by the purchaser's future drilling activities. The purchaser was required to drill two Woodford Shale well tests by July 31, 2015, the first to be spudded by September 1, 2014, or pay us certain additional amounts of cash for each well not drilled. The purchaser has drilled two Woodford Shale horizontal wells to date

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and a third well is currently being drilled on the checkerboard acreage assignment. The first well, the States 18-6-13 1H, has a 4,225-foot lateral and was completed with a 19-stage fracture stimulation. The States 18-6-13 1H's peak production rate was 229 Boe/d (59% oil) and the well has averaged 173 Boe/d (58% oil) during the first 21 days of production. The second well, the Engle 18-5-36 1H, has a 4,050-foot lateral and is currently in the process of being completed with an approximate 18-stage fracture stimulation.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Mid-Continent	2014	2013	2014	2013
Production:				
Oil and condensate (MBbl)	213	37	516	83
Natural gas (MMcf)	715	383	2,004	532
NGLs (MBbl)	83	7	232	8
Total Production (MBoe)	415	107	1,082	179
Oil and condensate (MBbl/d)	2.3	0.4	1.9	0.3
Natural gas (MMcf/d)	7.8	4.2	7.3	2.0
NGLs (MBbl/d)	0.9	0.1	0.9	—
Total daily production (MBoe/d)	4.5	1.2	4.0	0.7
Average sales price per unit (1):				
Oil and condensate (per Bbl)	$96.09	$102.61	$98.45	$96.38
Natural gas (per Mcf)	$3.87	$4.37	$4.46	$4.72
NGLs (per Bbl)	$30.42	$33.67	$34.83	$33.05
Average sales price per Boe (1)	$62.11	$52.90	$62.66	$60.01
Selected operating expenses (in thousands):				
Production taxes	$904	$207	$2,264	$296
Lease operating expenses	$3,160	$989	$9,793	$1,533
Transportation, treating and gathering	$9	$(7)	$31	$1
Selected operating expenses per Boe:				
Production taxes	$2.18	$1.92	$2.09	$1.65
Lease operating expenses	$7.62	$9.21	$9.05	$8.55
Transportation, treating and gathering	$0.02	$(0.07)	$0.03	$—
Production costs (2)	$7.64	$9.14	$9.08	$8.56

(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.

Appalachia.

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 stimulation have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of September 30, 2014, our acreage position in the play was approximately 74,600 gross (51,800 net) acres. We refer to the approximately 32,600 gross (14,000 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to the Atinum Joint Venture described below as our Marcellus West acreage. We refer to the approximately 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 play. We continue to opportunistically swap acreage with adjacent operators in order to optimize our acreage and maximize horizontal lateral lengths.

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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, Atinum and Gastar USA agreed to reduce the minimum wells to be drilled requirements by nine wells to 51 wells from 60 wells. At September 30, 2014, 57 gross operated Marcellus Shale horizontal wells were capable of production under the Atinum Joint Venture. All of our Marcellus Shale well operations to date were under the Atinum Joint Venture.

As of September 30, 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%	40.5%	6,100	Awaiting completion	Pending outcome of non-lessor surface owner dispute
Armstrong(3)	7.0	3.5	50.0%	40.5%	5,000	Three wells completed; four wells awaiting completion	December 2014
Hansen(4)	3.0	1.5	50.0%	40.5%	4,600	Awaiting completion	December 2014
Blake(5)	2.0	1.0	50.0%	40.5%	5,700	Top holes drilled	February 2015
	15.0	7.5					

(1) Average well lateral length approximates the actual average well lateral length for wells that have been completed and the estimated average well lateral length for wells that have not been completed.
(2) The Goudy pad is projected to ultimately have nine gross wells, four of which were placed on production in August 2013 and three of which are awaiting completion.
(3) The Armstrong pad is projected to ultimately have nine gross wells.
(4) The Hansen pad is projected to ultimately have ten gross wells.
(5) The Blake pad is projected to ultimately have nine gross wells.

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 it 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 approximately 28,400 gross (12,000 net) acres of our Marcellus West acreage, of which approximately 4,500 gross (2,000 net) acres are pending lease finalization, 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 that used approximately 10.6 million pounds of sand proppant. We “soaked” the well for approximately three weeks before turning the well to production on August 27, 2014. The well produced at an initial 48-hour gross sales rate of 29.4 MMcf/d of natural gas on a 30/64ths choke with approximately 6,700 psi of flowing casing pressure and averaged 19.8 MMcf/d of natural gas over the first 30 days of production. Our working interest in the Simms U-5H is 50.0% (43.2% net revenue interest). We will spud our second Utica Shale well, the Blake U-7H in late November 2014, and our working interest in the Blake U-7H is 50.0%. We anticipate that the Blake U-7H will be on production during late first quarter 2015. At September 30, 2014, one gross operated Utica Shale horizontal well was capable of production and all of our Utica Shale well operations to date were under the Atinum Joint Venture.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Appalachia	2014	2013	2014	2013
Production:				
Oil and condensate (MBbl)	37	88	144	240
Natural gas (MMcf)	2,112	2,644	6,575	7,063
NGLs (MBbl)	97	130	311	339
Total production (MBoe)	486	659	1,550	1,757
Oil and condensate (MBbl/d)	0.4	1.0	0.5	0.9
Natural gas (MMcf/d)	23.0	28.7	24.1	25.9
NGLs (MBbl/d)	1.1	1.4	1.1	1.2
Total daily production (MBoe/d)	5.3	7.2	5.7	6.4
Average sales price per unit (1)(2):				
Oil and condensate (per Bbl)	$62.57	$60.12	$77.28	$57.23
Natural gas (per Mcf)	$2.08	$2.30	$4.75	$2.81
NGLs (per Bbl)	$26.98	$33.79	$27.68	$29.94
Average sales price per Boe (1)(2)	$19.15	$23.94	$32.85	$24.92
Selected operating expenses (in thousands):				
Production taxes (3)	$654	$1,095	$3,226	$2,789
Lease operating expenses (3)	$976	$644	$3,264	$2,368
Transportation, treating and gathering (3)	$388	$153	$3,137	$563
Selected operating expenses per Boe:				
Production taxes (3)	$1.35	$1.66	$2.08	$1.59
Lease operating expenses (3)	$2.01	$0.98	$2.11	$1.35
Transportation, treating and gathering (3)	$0.80	$0.23	$2.02	$0.32
Production costs (4)	$2.45	$1.27	$3.74	$1.58

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(1) Excludes the impact of hedging activities.

(2) The nine months ended September 30, 2014 includes the benefit of a one-time revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Nine Months Ended September 30, 2014
Appalachia	
Average sales price per unit:	
Oil and condensate (per Bbl)	$55.42
Natural gas (per Mcf)	$3.51
NGLs (per Bbl)	$29.86
Average sales price per Boe	$26.01

(3) The nine months ended September 30, 2014 includes a one-time 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 Nine Months Ended September 30, 2014
Appalachia	
Selected operating expenses per Boe:	
Production taxes	$ 1.70
Lease operating expenses	$ 2.22
Transportation, treating and gathering	$ 1.00

(4) 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 nine months ended September 30, 2014 would have been as follows:

	For the Nine Months Ended September 30, 2014
Appalachia	
Selected operating expenses per Boe:	
Production costs	$ 2.84

Results of Operations

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In thousands, except per unit amounts)			
Production:				
Oil and condensate (MBbl)	250	128	660	333
Natural gas (MMcf)	2,826	3,866	8,579	10,257
NGLs (MBbl)	180	137	543	347
Total production (MBoe)	901	909	2,633	2,390
Daily production:				
Oil and condensate (MBbl/d)	2.7	1.4	2.4	1.2
Natural gas (MMcf/d)	30.7	42.0	31.4	37.6
NGLs (MBbl/d)	2.0	1.5	2.0	1.3
Total daily production (MBoe/d)	9.8	9.9	9.6	8.8
Average sales price per unit[(1)]:				
Oil and condensate per Bbl, excluding impact of hedging activities	$91.17	$73.40	$93.83	$68.26
Oil and condensate per Bbl, including impact of hedging activities [(2)]	$88.77	$67.92	$90.24	$68.54
Natural gas per Mcf, excluding impact of hedging activities	$2.53	$2.61	$4.68	$2.94
Natural gas per Mcf, including impact of hedging activities [(2)]	$2.56	$2.95	$4.29	$3.38
NGLs per Bbl, excluding impact of hedging activities	$28.56	$33.79	$30.74	$30.01
NGLs per Bbl, including impact of hedging activities [(2)]	$26.13	$27.54	$26.85	$30.80
Average sales price per Boe, excluding impact of hedging activities	$38.94	$26.52	$45.10	$26.47
Average sales price per Boe, including impact of hedging activities [(2)]	$37.87	$26.23	$42.13	$28.53
Selected operating expenses:				
Production taxes [(3)]	$1,558	$1,319	$5,489	$3,112
Lease operating expenses [(3)]	$4,136	$2,190	$13,057	$6,196
Transportation, treating and gathering [(3)]	$397	$1,098	$3,168	$3,386
Depreciation, depletion and amortization	$11,111	$8,467	$33,773	$21,428
General and administrative expense	$4,002	$3,998	$12,658	$11,964
Selected operating expenses per Boe:				
Production taxes [(3)]	$1.73	$1.45	$2.09	$1.30
Lease operating expenses [(3)]	$4.59	$2.41	$4.96	$2.59
Transportation, treating and gathering [(3)]	$0.44	$1.21	$1.20	$1.42
Depreciation, depletion and amortization	$12.33	$9.31	$12.83	$8.97
General and administrative expense	$4.44	$4.40	$4.81	$5.01
Production costs [(4)]	$4.84	$3.67	$5.93	$3.86

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(1)The nine months ended September 30, 2014 includes the benefit of a one-time revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Nine Months Ended September 30, 2014
Average sales price per unit:	
Oil and condensate per Bbl, excluding impact of hedging activities	$89.06
Oil and condensate per Bbl, including impact of hedging activities (2)	$85.47
Natural gas per Mcf, excluding impact of hedging activities	$3.73
Natural gas per Mcf, including impact of hedging activities (2)	$3.34
NGLs per Bbl, excluding impact of hedging activities	$31.99
NGLs per Bbl, including impact of hedging activities (2)	$28.09
Average sales price per Boe, excluding impact of hedging activities	$41.07
Average sales price per Boe, including impact of hedging activities (2)	$38.11

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

(3)The nine months ended September 30, 2014 includes a one-time 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 Nine Months Ended September 30, 2014
Selected operating expenses per Boe:	
Production taxes	$1.86
Lease operating expenses	$5.03
Transportation, treating and gathering	$0.60

(4)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 nine months ended September 30, 2014 would have been as follows:

	For the Nine Months Ended September 30, 2014
Selected operating expenses per Boe:	
Production costs	$5.40

Three Months Ended September 30, 2014 compared to the Three Months Ended September 30, 2013

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $35.1 million for the three months ended September 30, 2014, up 46% from $24.1 million for the three months ended September 30, 2013. The increase in revenues was the result of a 47% increase in weighted average realized prices partially offset by a 1% decrease in production. Average daily production on an equivalent basis was 9.8 MBoe/d for the three months ended September 30, 2014 compared to 9.9 MBoe/d for the same period in 2013. Oil, condensate and NGLs production represented approximately 48% of total production for the three months ended September 30, 2014 compared to 29% of total production for the three months ended September 30, 2013.

Liquids revenues (oil, condensate and NGLs) represented approximately 80% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2014 compared to 58% for the three months ended September 30, 2013. We are continuing to focus our drilling activity in the liquids-rich portions of the Marcellus Shale and the Mid-Continent oil play. If current trends of natural gas prices relative to oil, condensate and NGLs prices continue, and assuming that we successfully and timely complete our 2014 drilling activity, we expect our liquids revenues to continue to increase as a percentage of total oil, condensate, natural gas and NGLs revenues during the remainder of 2014.

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During the three months ended September 30, 2014, we had commodity derivative contracts covering approximately 87% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the quarter of $78,000 and resulted in an increase in total price realized from $2.53 per Mcf to $2.56 per Mcf. The gain on natural gas commodity derivative contracts settled during the period includes a loss of $94,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $88,000 of NYMEX hedge gains and $84,000 of basis hedge gains. For additional information regarding our natural gas hedging positions as of September 30, 2014, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report. During the three months ended September 30, 2013, the impact of hedging on natural gas sales was an increase of $1.3 million in natural gas revenues resulting in an increase in total price realized from $2.61 per Mcf to $2.95 per Mcf.

During the three months ended September 30, 2014, we had commodity derivative contracts covering approximately 43% of our oil and condensate production. The impact of hedging on oil and condensate sales during the three months ended September 30, 2014 was a decrease of $601,000 in oil and condensate revenues and resulted in a decrease in total price realized from $91.17 per Bbl to $88.77 per Bbl. The loss on oil and condensate commodity derivatives contracts settled during the period includes a loss of $9,000 for amortization of prepaid premiums and a loss of $18,000 of deferred put premiums. For additional information regarding our oil and condensate hedging positions as of September 30, 2014, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report. During the three months ended September 30, 2013, the impact of hedging on oil and condensate sales was a decrease of $701,000 in oil and condensate revenues, which resulted in a decrease in total price realized from $73.40 per Bbl to $67.92 per Bbl. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

During the three months ended September 30, 2014, we had commodity derivative contracts covering approximately 85% of our NGLs production. The impact of hedging on NGLs sales during the three months ended September 30, 2014 was a decrease of $437,000 in NGLs revenues and resulted in a decrease in total price realized from $28.56 per Bbl to $26.13 per Bbl. The loss on NGLs commodity derivatives contracts settled during the period includes a loss of $9,000 for amortization of prepaid premiums and a loss of $18,000 of deferred put premiums. For additional information regarding our NGLs hedging positions as of September 30, 2014, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report. During the three months ended September 30, 2013, the impact of hedging on NGLs sales was a decrease of $855,000 in NGLs revenues which resulted in a decrease in total price realized from $33.79 per Bbl to $27.54 per Bbl.

The change in mark to market value for outstanding commodity derivatives contracts for the three months ended September 30, 2014 was a gain of $7.6 million compared to losses of $5.0 million for the three months ended September 30, 2013. The change in the mark to market value is primarily the result of lower commodity prices and the changes in hedge contracts during the period compared to the prior year.

Production taxes. We reported production taxes of $1.6 million for the three months ended September 30, 2014 compared to $1.3 million for the three months ended September 30, 2013. The increase in production taxes primarily resulted from higher revenues in Oklahoma due to increased oil, condensate, natural gas and NGLs production from new wells drilled or acquired partially offset by lower revenues in West Virginia due to decreased volumes and lower natural gas prices. Production taxes for the three months ended September 30, 2014 and 2013 were approximately 4% and 5%, respectively, of oil, condensate, natural gas and NGLs revenues. The decrease in the production tax as a percentage of revenues is primarily the result of an increase in Mid-Continent revenues that benefit from a production tax abatement related to new horizontal well drilling.

Lease operating expenses. We reported lease operating expenses ("LOE") of $4.1 million for the three months ended September 30, 2014 compared to $2.2 million for the three months ended September 30, 2013. Our total LOE was $4.59 per Boe for the three months ended September 30, 2014 compared to $2.41 per Boe for the same period in 2013. The increase in our LOE was primarily due to a $1.8 million increase in controllable LOE resulting from new wells and higher overall costs associated with producing oil versus natural gas.

Transportation, treating and gathering. We reported transportation expenses of $397,000 for the three months ended September 30, 2014 compared to $1.1 million for the three months ended September 30, 2013. The decrease in transportation expenses between quarters is primarily due to the elimination of approximately $946,000 of transportation fees due to the sale of our East Texas properties on October 2, 2013 partially offset by higher transportation and marketing fees on our Appalachia horizontal wells.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization (“DD&A”) expense of $11.1 million for the three months ended September 30, 2014 up from $8.5 million for the three months ended September 30, 2013. The increase in DD&A expense was the result of a 32% increase in the DD&A rate per Boe partially offset by a 1% decrease in production. The DD&A rate for the three months ended September 30, 2014 was $12.33 per Boe compared to $9.31 per Boe for the same period in 2013. The increase in the rate is primarily due to 2013 higher cost liquids (oil, condensate and

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NGLs) focused acquisitions and drilling resulting in an increase in our total liquids production as a percentage of total production for the third quarter of 2014 of 48% compared to 29% for the same period in 2013.
General and administrative expense. We reported general and administrative expenses of $4.0 million for the three months ended September 30, 2014 and 2013. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $1.2 million for the three months ended September 30, 2014 compared to $574,000 for the three months ended September 30, 2013. Excluding stock-based compensation expense, general and administrative expense decreased $594,000 to $2.8 million for the three months ended September 30, 2014 compared to the three months ended September 30, 2013. This decrease is primarily due to severance costs related to the East Texas property disposition and acquisition costs incurred during the three months ended September 30, 2013, partially offset by higher personnel costs for the three months ended September 30, 2014 due to a larger asset base compared to the prior period.
Interest expense. We reported interest expense of $7.0 million for the three months ended September 30, 2014 compared to $3.4 million for the three months ended September 30, 2013. The increase in interest expense is directly related to the issuance in May and November of 2013 of $200.0 million and $125.0 million, respectively, of our Notes.
Dividends on preferred stock. We reported dividends on preferred stock of $3.6 million for the three months ended September 30, 2014 compared to $2.1 million for the three months ended September 30, 2013. The Series A Preferred Stock had a stated value of approximately $78.8 million and $76.8 million at September 30, 2014 and 2013, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $2.2 million and $2.1 million for the three months ended September 30, 2014 and 2013, respectively. There were 4,045,000 shares and 3,958,160 shares of Series A Preferred Stock outstanding at September 30, 2014 and 2013, respectively. The Series B Preferred Stock, issued during November 2013, had a stated value of approximately $50.0 million at September 30, 2014 and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $1.4 million for the three months ended September 30, 2014. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at September 30, 2014, our future stated preferred dividend expense is approximately $3.6 million per quarter, which is subject to being declared and paid monthly.

Nine Months Ended September 30, 2014 compared to the Nine Months Ended September 30, 2013
Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $118.7 million for the nine months ended September 30, 2014, up 88% from $63.3 million for the nine months ended September 30, 2013. The increase in revenues was the result of a 10% increase in production and a 70% increase in weighted average realized prices. Excluding the benefit of a one-time revenue adjustment of $10.6 million related to an arbitration settlement, weighted average barrel of oil equivalent realized prices increased 55% for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. Average daily production on an equivalent basis was 9.6 MBoe/d for the nine months ended September 30, 2014 compared to 8.8 MBoe/d for the same period in 2013. Oil, condensate and NGLs production represented approximately 46% of total production for the nine months ended September 30, 2014 compared to 28% of total production for the nine months ended September 30, 2013. The one-time arbitration settlement did not have any impact on production volumes.
Liquids revenues (oil, condensate and NGLs) represented approximately 66% of our total oil, condensate, natural gas and NGLs revenues for the nine month period ended September 30, 2014 compared to 52% for the nine month period ended September 30, 2013. Excluding a one-time adjustment related to an arbitration settlement, liquids revenues represented approximately 70% of our total oil, condensate, natural gas and NGLs revenues for the nine month period ended September 30, 2014. We are continuing to focus the majority of our drilling activity in the liquids-rich portions of the Marcellus Shale and the Mid-Continent oil play. If current trends of natural gas prices relative to oil, condensate and NGLs prices continue, and assuming that we successfully and timely complete our 2014 drilling activity, we expect our liquids revenues to continue to increase as a percentage of total oil, condensate, natural gas and NGLs revenues during the remainder of 2014.
During the nine months ended September 30, 2014, we had commodity derivative contracts covering approximately 87% of our natural gas production, which resulted in a loss on natural gas commodity derivatives contracts settled

during the nine months ended September 30, 2014 of $3.3 million and resulted in a decrease in total price realized from $4.68 per Mcf to $4.29 per Mcf. Excluding the benefit of the one-time revenue adjustment related to an arbitration settlement, the total price realized for natural gas including the loss on natural gas commodity derivatives contracts settled during the nine months ended September 30, 2014 would have decreased from $3.73 per Mcf to $3.34 per Mcf. The loss on commodity derivative contracts settled during the period includes a loss of $217,000 for amortization of prepaid premiums partially offset by a gain on basis hedges of $84,000. For additional information regarding our natural gas hedging positions as of September 30, 2014, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report. During the nine months ended September 30, 2013, the impact of hedging on natural gas sales was an increase of $4.6 million in natural gas revenues resulting in an increase in total price realized from $2.94 per Mcf to $3.38 per Mcf.

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During the nine months ended September 30, 2014, we had commodity derivative contracts covering approximately 54% of our oil and condensate production. The impact of hedging on oil and condensate sales during the nine months ended September 30, 2014 was a decrease of $2.4 million in oil and condensate revenues and resulted in a decrease in total price realized from $93.83 per Bbl to $90.24 per Bbl. Excluding the benefit of the one-time revenue adjustment related to an arbitration settlement, the total price realized for oil and condensate including the loss on oil and condensate commodity derivatives contracts settled during the nine months ended September 30, 2014 would have decreased from $89.06 per Bbl to $85.47 per Bbl. The loss on oil and condensate commodity derivatives contracts settled during the period includes a loss of $27,000 for amortization of prepaid premiums and a loss of $18,000 on deferred put premiums. For additional information regarding our oil and condensate hedging positions as of September 30, 2014, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report. During the nine months ended September 30, 2013, the impact of hedging on oil and condensate sales was an increase of $92,000 in oil and condensate revenues, which resulted in an increase in total price realized from $68.26 per Bbl to $68.54 per Bbl. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

During the nine months ended September 30, 2014, we had commodity derivative contracts covering approximately 85% of our NGLs production. The impact of hedging on NGLs sales during the nine months ended September 30, 2014 was a decrease of $2.1 million in NGLs revenues and resulted in a decrease in total price realized from $30.74 per Bbl to $26.85 per Bbl. Excluding the impact of the one-time revenue adjustment related to an arbitration settlement and related adjustments, the total price realized for NGLs including the loss on NGLs commodity derivatives contracts settled during the nine months ended September 30, 2014 would have decreased from $31.99 per Bbl to $28.09 per Bbl. The loss on NGLs commodity derivatives contracts settled during the period includes a loss of $27,000 for amortization of prepaid premiums and a loss of $18,000 on deferred put premiums. For additional information regarding our NGLs hedging positions as of September 30, 2014, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report. During the nine months ended September 30, 2013, the impact of hedging on NGLs sales was an increase of $275,000 in NGLs revenues which resulted in an increase in total price realized from $30.01 per Bbl to $30.80 per Bbl.

Losses related to the change in mark to market value for outstanding commodity derivatives contracts for the nine months ended September 30, 2014 were $950,000 compared to losses of $7.2 million for the nine months ended September 30, 2013. The decrease in the mark to market loss is primarily the result of lower commodity prices and the changes in hedge contracts during the period.

Production taxes. We reported production taxes of $5.5 million for the nine months ended September 30, 2014 compared to $3.1 million for the nine months ended September 30, 2013. Production taxes reported for the nine months ended September 30, 2014 include $584,000 of additional production taxes attributed to the one-time revenue adjustment resulting from an arbitration settlement. Excluding the adjustment, the increase in production taxes primarily resulted from higher revenues in Oklahoma due to increased oil, condensate, natural gas and NGLs production from new wells drilled or acquired. Production taxes for the nine months ended September 30, 2014 and 2013 were approximately 5% of oil, condensate, natural gas and NGLs revenues.

Lease operating expenses. We reported LOE of $13.1 million for the nine months ended September 30, 2014 compared to $6.2 million for the nine months ended September 30, 2013. Our total LOE was $4.96 per Boe for the nine months ended September 30, 2014 compared to $2.59 per Boe for the same period in 2013. Excluding $185,000 of a one-time reduction to LOE related to an arbitration settlement, our total LOE would have been $5.03 per Boe for the nine months ended September 30, 2014. The increase in our LOE was primarily due to a $7.0 million increase in controllable LOE resulting from new wells and higher overall costs associated with producing oil versus natural gas and an increase in ad valorem taxes of $250,000 partially offset by a $267,000 decrease in workover costs and a $118,000 decrease in insurance costs. The nine months ended September 30, 2014 also includes approximately $350,000 of LOE costs associated with pump repair and scale removal.

Transportation, treating and gathering. We reported transportation expenses of $3.2 million for the nine months ended September 30, 2014 compared to $3.4 million for the nine months ended September 30, 2013. Transportation, treating and gathering expense reported for the nine months ended September 30, 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 to date transportation expense would have been $1.6 million. The decrease in adjusted transportation expense from September 30, 2013 to September 2014 is primarily due to the elimination of approximately $2.8 million of transportation fees due to the sale of our East Texas properties on October 2, 2013, partially offset by higher transportation and marketing fees on our Appalachia wells.

Depreciation, depletion and amortization. We reported DD&A expense of $33.8 million for the nine months ended September 30, 2014 up from $21.4 million for the nine months ended September 30, 2013. The increase in DD&A expense was the result of a 10% increase in production and a 43% increase in the DD&A rate per Boe. The DD&A rate for the nine months ended September 30, 2014 was $12.83 per Boe compared to $8.97 per Boe for the same period in 2013. The increase in the rate is primarily due to 2013 higher cost liquids (oil, condensate and NGLs) focused acquisitions and drilling resulting in an

increase in our total liquids production as a percentage of total production for the nine months ended September 30, 2014 of 46% compared to 28% for the same period in 2013.
General and administrative expense. We reported general and administrative expenses of $12.7 million for the nine months ended September 30, 2014, up from $12.0 million for the nine months ended September 30, 2013. Non-cash stock-based compensation expense, which is included in general and administrative expense, increased $1.2 million to $3.7 million for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. 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 employees coupled with an increase in 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 $470,000 to $9.0 million for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. This decrease is primarily due to lower acquisition costs offset by higher personnel costs, professional fees and public company expenses. The nine months ended September 30, 2014 and 2013 included $233,000 and $590,000, respectively, of parent migration costs.
Litigation settlement expense. We did not report any litigation settlement expense for the nine months ended September 30, 2014. We reported $1.0 million of litigation settlement expense for the nine months ended September 30, 2013 for the settlement of litigation with Chesapeake on March 28, 2013.
Gain on acquisition of assets at fair value. We reported a bargain purchase gain of $43.7 million for the nine months ended September 30, 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 $113.5 million. As a result of incorporating the valuation information into the purchase price allocation, a bargain purchase gain of $43.7 million was recognized during the second quarter of 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. With the completion of the asset valuation during the fourth quarter of 2013, we recorded deferred tax expense associated with the gain of $16.0 million. As a result of incorporating the final valuation information into the purchase price allocation, a net after tax bargain purchase gain of $27.7 million was recognized in 2013. Due to our existing net operating loss tax position, we also recognized a corresponding income tax benefit of $16.0 million in the fourth quarter of 2013.
Interest expense. We reported interest expense of $20.8 million for the nine months ended September 30, 2014 compared to $7.6 million for the nine months ended September 30, 2013. The increase in interest expense is directly related to the issuance in May and November of 2013 of $200.0 million and $125.0 million, respectively, of our Notes.
Dividends on preferred stock. We reported dividends on preferred stock of $10.8 million for the nine months ended September 30, 2014 compared to $6.4 million for the nine months ended September 30, 2013. The Series A Preferred Stock had a stated value of approximately $78.8 million and $76.8 million at September 30, 2014 and 2013, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $6.5 million and $6.4 million for the nine months ended September 30, 2014 and 2013, respectively. There were 4,045,000 shares and 3,958,160 shares of Series A Preferred Stock outstanding at September 30, 2014 and 2013, respectively. The Series B Preferred Stock, issued during November 2013, had a stated value of approximately $50.0 million at September 30, 2014 and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $4.3 million for the nine months ended September 30, 2014. Based on the number of shares of Series A Preferred Stock and Series B Preferred Stock outstanding at September 30, 2014, our future stated preferred dividend expense is approximately $3.6 million per quarter, which is subject to being declared and paid monthly.

Liquidity and Capital Resources
Overview. Our primary sources of liquidity and capital resources are internally generated cash flows from operating activities or asset sales, availability under the Revolving Credit Facility, issuances of additional senior secured notes or preferred or common equity and access to capital markets, to the extent available. 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 our future capital expenditures in response to changes in oil, condensate, natural gas and NGLs prices, drilling results and cash flow.

For the nine months ended September 30, 2014, we reported cash flows provided by operating activities of $60.3 million. For the nine months ended September 30, 2014, we reported net cash used in investing activities of $134.7 million primarily for the development and purchase of oil and natural gas properties. For the nine months ended September 30, 2014, we reported net cash provided by financing activities of $88.7 million, consisting primarily of $101.5 million of net proceeds from the issuance of common stock and $2.1 million of net proceeds from the issuance of Series A Preferred Stock partially offset by

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$10.8 million of dividends paid on the preferred stock and $3.7 million of tax withholding related to restricted stock and PBU vestings during the period. As a result of these activities, our cash and cash equivalents balance increased by $14.2 million, resulting in a cash and cash equivalents balance of $46.6 million at September 30, 2014.

At September 30, 2014, we had a net working capital surplus of approximately $12.4 million. At September 30, 2014, availability under our Revolving Credit Facility was $145.0 million.

Future capital and other expenditure requirements. Capital expenditures for the remainder of 2014, excluding acquisitions, are currently projected to be approximately $79.3 million. In Appalachia and Mid-Continent, we expect to spend $40.8 million and $36.4 million, respectively, for drilling, completion, infrastructure, lease acquisition and seismic costs. In addition, we have allocated $2.1 million for capitalized interest and other costs. We plan to fund our remaining 2014 capital budget through existing cash balances, internally generated cash flow from operating activities and borrowings under the Revolving Credit Facility, or some combination thereof.

Our current 2015 budgeted capital expenditures include approximately $138.2 million of drilling, completion and infrastructure costs, which is expected to provide for 31 gross (15.4 net) wells in the Hunton Limestone play, three gross (1.5 net) wells in the Marcellus Shale play, and one gross (0.5 net) well in the Utica Shale play. Our current 2015 capital budget also includes approximately $28.0 million of land and seismic expenditures and other capitalized costs of approximately $6.4 million, resulting in a total 2015 capital budget of approximately $172.6 million. 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 the possible divestiture of assets or some combination thereof.

We are closely monitoring the recent volatility in the commodity markets, in particular the recent drop in oil prices and widening of basis differentials in Appalachia, and we are developing capital plans responsive to changes that are occurring in the commodity and capital markets. Our future 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 81% of our remaining budgeted 2014 capital expenditures, and thus, we could reduce a significant portion of 2014 capital expenditures if necessary to better match available capital resources.

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

To mitigate some of the potential negative impact on cash flows caused by changes in oil, condensate, natural gas and NGLs prices, we have entered into financial commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge oil, condensate, natural gas and NGLs price risk. The crude oil fixed price swaps provide price protection for our future oil sales and butane, isobutene and pentanes components of our NGLs production as these heavy components of NGLs have pricing that correlates closely with oil pricing. We have designated 50% of our current crude hedges as price protection for a portion of our NGLs production. For additional information regarding our hedging activities, see Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report.

At September 30, 2014, the estimated fair value of all of our commodity derivative instruments was a net asset of $2.9 million, comprised of current and non-current assets and liabilities. By removing the price volatility from a portion of our oil, condensate, natural gas and NGLs sales for 2014 through 2018, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flows for those periods. While mitigating negative effects of falling commodity prices, certain derivative contracts also limit the benefits we could receive from increases in commodity prices. In conjunction with certain commodity derivative hedging activity, we deferred the payment of certain put premiums for the production month period September 2014 through August 2018. At September 30, 2014, we had a current commodity premium payable of $2.0 million and a long-term commodity premium payable of $5.3 million. The put premium liabilities become payable monthly as the hedge production month becomes the prompt

production month.
As of September 30, 2014, all of our commodity derivative hedge positions were with a multinational energy company or large financial institutions, each of which is not known to us to be in default on their derivative positions. We are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, we do not anticipate non-performance by such counterparties.
Revolving Credit Facility. Effective June 7, 2013, we amended and restated our revolving credit facility. As amended, our Revolving Credit Facility had an initial borrowing base of $50.0 million. On March 26, 2014, the borrowing base under the Revolving Credit Facility was increased by the lending participants to $120.0 million and subsequently to $145.0 million on August 3, 2014. At September 30, 2014, we did not have any borrowings outstanding under our Revolving Credit Facility.

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Borrowing base redeterminations are scheduled semi-annually with the next regularly scheduled redetermination scheduled for May 2015. However, we and the lenders may each request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. Borrowings under the Revolving Credit Facility bear interest, at our election, at the reference rate or the Eurodollar rate plus an applicable margin. Pursuant to the Revolving Credit Facility, the reference rate is the greater of (i) the rate of interest publicly announced by the administrative agent or (ii) the federal funds rate plus 50 basis points. The applicable interest rate margin varies from 1.0% to 2.0% in the case of borrowings based on the reference rate and from 2.0% to 3.0% in the case of borrowings based on the Eurodollar rate, depending on the utilization percentage in relation to the borrowing base. Under the Revolving Credit Facility, we are subject to certain financial covenants, including interest coverage ratio, a total net indebtedness to EBITDA ratio and current ratio requirement, as adjusted. On November 3, 2014, our availability under our Revolving Credit Facility was $145.0 million.

At September 30, 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 Part I, Item 1. “Financial Statements, Note 4 – Long-Term Debt” of this report.

Senior Secured Notes. During 2013, we issued by private placements under an indenture of $325.0 million aggregate principal amount of our Notes. The Notes bear interest at a rate of 8.625% per year, payable semiannually in arrears on May 15 and November 15 of each year. In May 2014, holders of our Notes exchanged their notes for registered notes with the same terms. For a more detailed description of the terms of our Notes, see Part I, Item 1. “Financial Statements, Note 4 - Long-Term Debt - Senior Secured Notes” of this report. At September 30, 2014, we were in compliance with all covenants under the indenture governing the Notes.

Series A Preferred Stock. For the nine months ended September 30, 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 three and nine months ended September 30, 2014, we recognized dividend expense of $2.2 million and $6.5 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 the stated par value of $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 three and nine months ended September 30, 2014, we recognized dividend expense of $1.4 million and $4.3 million, respectively, for the Series B Preferred Stock.

Off-Balance Sheet Arrangements

As of September 30, 2014, we had no off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Commitments and Contingencies

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

We are party to various litigation matters and administrative claims arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows. A discussion of current legal proceedings is set forth in Part I, Item 1. “Financial Statements, Note 12 – Commitments and Contingencies” of this report.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, contingent assets and liabilities and the related disclosures in the accompanying condensed consolidated financial statements. Changes in these

estimates and assumptions could materially affect our financial position, results of operations or cash flows.
Management considers an accounting estimate to be critical if:

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

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Significant accounting policies that we employ and information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate are presented in Part I, Item I. “Financial Statements, Note 2 – Summary of Significant Accounting Policies” of this report and in Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates” included in our 2013 Form 10-K.

Recent Accounting Developments

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major commodity price risk exposure is to the prices received for our 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 the exposure to adverse market changes, we have entered into various derivative instruments. For the three and nine months ended September 30, 2014, a 10% change in the prices received for oil, condensate, natural gas and NGLs production, excluding the benefit of a one-time adjustment related to settlement arbitration for the nine month period, would have had an approximate $3.5 million and $10.8 million impact, respectively, on our revenues prior to hedge transactions to mitigate our commodity pricing risk. See Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report for additional information regarding our hedging activities.

Interest Rate Risk

At September 30, 2014, we did not have any borrowings outstanding under the Revolving Credit Facility. The amount outstanding under the Notes is at fixed interest of 8.625% per annum. We currently do not use interest rate derivatives to mitigate our exposure to the volatility in interest rates, including under the Revolving Credit Facility, as this risk is minimal.

Item 4. Controls and Procedures

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

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (“Exchange Act”), as of September 30, 2014. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2014, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Information about material risks related to our business, financial condition and results of operations for the three and nine months ended September 30, 2014 does not materially differ from that set out under Part I, Item 1A. “Risk Factors” in our 2013 Form 10-K. You should carefully consider the risk factors and other information discussed in our 2013 Form 10-K, as well as the information provided in this report. These risks are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, operating results and cash flows.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The exhibits required to be filed or furnished pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Form 10-Q and are incorporated herein by reference.

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SIGNATURES

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

		GASTAR EXPLORATION INC.
Date: November 6, 2014	By:	/S/ J. RUSSELL PORTER J. Russell Porter President and Chief Executive Officer (Duly authorized officer and principal executive officer)
Date: November 6, 2014	By:	/S/ MICHAEL A. GERLICH Michael A. Gerlich Senior Vice President and Chief Financial Officer (Duly authorized officer and principal financial and accounting officer)

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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).

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2.12**	Agreement of Sale and Purchase, dated September 4, 2013, by and among Gastar Exploration USA, Inc., Lime Rock Resources II-A, L.P. and Lime Rock Resources II-C, L.P. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
2.13	Amended and Restated Plan of Arrangement Under Section 193 of the Business Corporations Act (Alberta), effective as of November 14, 2013 (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on November 15, 2013. File No. 001-32714).
2.14	Agreement and Plan of Merger, dated as of January 31, 2014, among Gastar Exploration, Inc. and Gastar Exploration USA, Inc. (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on January 31, 2014. File No. 000-55138).
3.1	Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.2	Second Amended and Restated Bylaws of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.2 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.3	Certificate of Merger of Gastar Exploration, Inc. into Gastar Exploration USA, Inc. (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).
10.1*	Form of Indemnification Agreement with Directors and/or Executive Officers of the Company (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).
10.2	Master Assignment, Agreement and Amendment No. 4 to Second Amended and Restated Credit Agreement, dated August 13, 2014 (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).
31.1†	

	Certification of Principal Executive Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1††	Certification of Principal Executive Officer and Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS†	XBRL Instance Document
101.SCH†	XBRL Taxonomy Extension Schema Document
101.CAL†	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	XBRL Taxonomy Extension Label Linkbase Document

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101.PRE†	XBRL Taxonomy Extension Presentation Linkbase Document

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† Filed herewith.

†† By SEC rules and regulations, deemed not filed for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, nor shall it be deemed incorporated by reference into any filing under the Securities Act, or the Exchange Act.

* Management plan or compensatory plan or arrangement.

** Pursuant to Item 601(b)(2) of Regulation S-K, the schedules and similar attachments to Exhibits 2.1, 2.2, 2.3 and 2.12 have not been filed herewith. The registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.