Gastar Exploration Inc.
Form 10-Q
November 03, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2016

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number: 001-35211

GASTAR EXPLORATION INC.

(Exact name of registrant as specified in its charter)

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

(713) 739-1800

(Registrant's telephone number, including area code)

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 No

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 No

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

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

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

The total number of outstanding common shares, $0.001 par value per share, as of November 1, 2016 was 131,723,116.

GASTAR EXPLORATION INC.

QUARTERLY REPORT ON FORM 10-Q

For the three and nine months ended September 30, 2016

TABLE OF CONTENTS

On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation, changed its jurisdiction of incorporation to the State of Delaware and changed its name to “Gastar Exploration, Inc.” On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar Exploration USA, Inc., its direct subsidiary, as part of a reorganization to eliminate Gastar Exploration, Inc.’s holding company corporate structure. Pursuant to the merger agreement, shares of Gastar Exploration, Inc.’s common stock were converted into an equal number of shares of common stock of Gastar Exploration USA, Inc., and Gastar Exploration USA, Inc. changed its name to “Gastar Exploration Inc.” Gastar Exploration Inc. owns and continues to conduct Gastar Exploration, Inc.’s business in substantially the same manner as was being conducted prior to the merger.

Unless otherwise indicated or required by the context, (i) for any date or period prior to the January 31, 2014 merger described above, “Gastar,” the “Company,” “we,” “us,” “our” and similar terms refer collectively to Gastar Exploration, Inc.(formerly known as Gastar Exploration Ltd.) and its subsidiaries, including Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.), and for any date or period after January 31, 2014, such terms refer collectively to Gastar Exploration Inc. and its subsidiaries and (ii) all dollar amounts appearing in this Form 10-Q are stated in United States dollars (“U.S. dollars”) unless otherwise noted and (iii) 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”).

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.

Glossary of Terms

AMI	Area of mutual interest, an agreed designated geographic area where co-participants or other industry participants 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, calculated by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
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
Gross acres	Refers to acres in which we own a working interest
Gross wells	Refers to wells in which we have a working interest
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condensate or NGLs per day
MBoe	One thousand barrels of oil equivalent, calculated by converting natural gas volumes on the basis of 6 Mcf of natural gas per barrel
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 by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
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 by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
MMcfe/d	One million cubic feet of natural gas equivalent per day
Net acres	Refers to our proportionate interest in acreage resulting from our ownership in gross acreage
Net wells	Refers to gross wells multiplied by our working interest in such wells
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
PBU	Performance based unit comprising one of our compensation plan awards
psi	Pounds per square inch
PUD	Proved undeveloped reserves
STACK Play	An acronymic name for a predominantly oil producing play referring to the exploration and development of the Sooner Trend of the Anadarko Basin in Canadian and Kingfisher Counties, Oklahoma

U.S.	United States of America
U.S. GAAP	Accounting principles generally accepted in the United States of America
WOC	Waiting on completion
WTI	West Texas Intermediate

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

GASTAR EXPLORATION INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2016 (Unaudited)	December 31, 2015
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$46,739	$50,074
Accounts receivable, net of allowance for doubtful accounts of $1,953 and $0, respectively	8,476	14,302
Commodity derivative contracts	5,240	15,534
Prepaid expenses	4,694	5,056
Total current assets	65,149	84,966
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	109,267	92,609
Proved properties	1,242,667	1,286,373
Total oil and natural gas properties	1,351,934	1,378,982
Furniture and equipment	2,615	3,068
Total property, plant and equipment	1,354,549	1,382,050
Accumulated depreciation, depletion and amortization	(1,125,881)	(1,053,116)
Total property, plant and equipment, net	228,668	328,934
OTHER ASSETS:		
Commodity derivative contracts	3,915	9,335
Deferred charges, net	616	985
Advances to operators and other assets	498	331
Other	1,121	4,944
Total other assets	6,150	15,595
TOTAL ASSETS	$299,967	$429,495
LIABILITIES AND STOCKHOLDERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable	$4,585	$2,029
Revenue payable	5,667	5,985
Accrued interest	10,517	3,730
Accrued drilling and operating costs	5,250	2,010
Advances from non-operators	110	167
Commodity derivative contracts	102	—
Commodity derivative premium payable	1,750	3,194

Asset retirement obligation	89	89
Other accrued liabilities	7,296	6,764
Total current liabilities	35,366	23,968
LONG-TERM LIABILITIES:		
Long-term debt	418,620	516,476
Commodity derivative contracts	—	451
Commodity derivative premium payable	1,427	2,788
Asset retirement obligation	5,626	5,997
Total long-term liabilities	425,673	525,712
Commitments and contingencies (Note 11)		
STOCKHOLDERS' DEFICIT:		
Preferred stock, 40,000,000 shares authorized		
Series A Preferred stock, par value $0.01 per share; 10,000,000 shares designated; 4,045,000 shares issued and outstanding at September 30, 2016 and December 31, 2015, respectively, with liquidation preference of $25.00 per share	41	41
Series B Preferred stock, par value $0.01 per share; 10,000,000 shares designated; 2,140,000 shares issued and outstanding at September 30, 2016 and December 31, 2015, respectively, with liquidation preference of $25.00 per share	21	21
Common stock, par value $0.001 per share; 550,000,000 and 275,000,000 shares authorized at September 30, 2016 and December 31, 2015, respectively; 131,725,215 and 80,024,218 shares issued and outstanding at September 30, 2016 and December 31, 2015, respectively	132	80
Additional paid-in capital	626,379	571,947
Accumulated deficit	(787,645)	(692,274)
Total stockholders' deficit	(161,072)	(120,185)
TOTAL LIABILITIES AND STOCKHOLDERS' DEFICIT	$299,967	$429,495

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

GASTAR EXPLORATION INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	For the Three Months Ended September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
	(in thousands, except share and per share data)			
REVENUES:				
Oil and condensate	$10,306	$12,835	$30,464	$45,772
Natural gas	2,500	3,459	8,394	14,109
NGLs	1,695	791	5,100	5,071
Total oil, condensate, natural gas and NGLs revenues	14,501	17,085	43,958	64,952
(Loss) gain on commodity derivatives contracts	(1,498)	11,301	(3,991)	19,734
Total revenues	13,003	28,386	39,967	84,686
EXPENSES (BENEFIT):				
Production taxes	400	655	1,469	2,317
Lease operating expenses	5,166	5,214	15,829	18,475
Transportation, treating and gathering	338	615	1,346	1,654
Depreciation, depletion and amortization	5,223	15,394	24,543	45,945
Impairment of oil and natural gas properties	—	181,966	48,497	282,118
Accretion of asset retirement obligation	92	131	286	387
General and administrative expense	3,925	4,683	15,872	13,352
Litigation settlement benefit	(10,100)	—	(10,100)	—
Total expenses	5,044	208,658	97,742	364,248
INCOME (LOSS) FROM OPERATIONS	7,959	(180,272)	(57,775)	(279,562)
OTHER INCOME (EXPENSE):				
Interest expense	(8,178)	(7,933)	(26,739)	(22,430)
Investment income and other (expense)	41	4	(2)	10
LOSS BEFORE PROVISION FOR INCOME TAXES	(178)	(188,201)	(84,516)	(301,982)
Provision for income taxes	—	—	—	—
NET LOSS	(178)	(188,201)	(84,516)	(301,982)
Dividends on preferred stock	(3,618)	(3,618)	(10,855)	(10,855)
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(3,796)	$(191,819)	$(95,371)	$(312,837)
NET LOSS PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:				
Basic	$(0.03)	$(2.47)	$(0.92)	$(4.04)
Diluted	$(0.03)	$(2.47)	$(0.92)	$(4.04)
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:				
Basic	129,301,817	77,628,120	104,125,317	77,453,251
Diluted	129,301,817	77,628,120	104,125,317	77,453,251

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

GASTAR EXPLORATION INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	For the Nine Months Ended September 30,	
	2016	2015
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(84,516)	$(301,982)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	24,543	45,945
Impairment of oil and natural gas properties	48,497	282,118
Stock-based compensation	3,145	3,927
Mark to market of commodity derivatives contracts:		
Total loss (gain) on commodity derivatives contracts	3,991	(19,734)
Cash settlements of matured commodity derivatives contracts, net	10,690	17,913
Cash premiums paid for commodity derivatives contracts	(565)	(45)
Amortization of deferred financing costs	3,812	2,652
Accretion of asset retirement obligation	286	387
Settlement of asset retirement obligation	(87)	(80)
Loss on sale of furniture and equipment	97	-
Changes in operating assets and liabilities:		
Accounts receivable	3,861	22,552
Prepaid expenses	362	1,472
Accounts payable and accrued liabilities	7,656	(289)
Net cash provided by operating activities	21,772	54,836
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of oil and natural gas properties	(43,175)	(121,074)
Reimbursements from (advances to) operators	211	(2,325)
Acquisition of oil and natural gas properties - refund	1,149	—
Proceeds from sale of oil and natural gas properties	77,499	47,866
Payments to non-operators	(57)	(1,820)
Proceeds from sale (purchase) of furniture and equipment	80	(51)
Net cash provided by (used in) investing activities	35,707	(77,404)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	-	75,000
Repayment of revolving credit facility	(100,370)	(40,000)
Proceeds from issuance of common stock, net of issuance costs	44,815	—
Dividends on preferred stock	(3,618)	(10,855)
Deferred financing charges	(930)	(804)
Tax withholding related to restricted stock and performance based unit award vestings	(711)	(1,430)
Net cash (used in) provided by financing activities	(60,814)	21,911
NET DECREASE IN CASH AND CASH EQUIVALENTS	(3,335)	(657)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	50,074	11,008

CASH AND CASH EQUIVALENTS, END OF PERIOD	$46,739	$10,351

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

GASTAR EXPLORATION INC.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Description of Business

Gastar Exploration Inc. (the "Company" or "Gastar") is a pure play Mid-Continent independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs. Gastar's principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. Gastar holds a concentrated acreage position in what is believed to be the core of the STACK Play, an area of central Oklahoma which is home to multiple oil and natural gas-rich reservoirs including the Oswego limestone, Meramec and Osage bench formations within the Mississippi Lime, the Woodford shale and Hunton limestone formations. On April 8, 2016, Gastar sold substantially all of its producing assets and proved reserves and a significant portion of its undeveloped acreage in the Appalachian Basin for an adjusted sales price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer, with an effective date of January 1, 2016 (the "Appalachian Basin Sale").

For any date or period prior to January 31, 2014, "Gastar," the "Company," "we," "us," "our" and similar terms refer collective 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.

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, 2015 (the "2015 Form 10-K") filed with the SEC. Please refer to the notes to the consolidated financial statements included in the 2015 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.

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 2015 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 2015 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, 2016 are not necessarily indicative of the results that may be expected for the year ending December 31, 2016.

Subsequent Events

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

Revolving Credit Facility

On October 14, 2016, the Company, together with the parties thereto, entered into Amendment No. 9 to Second Amended and Restated Credit Agreement ("Amendment No. 9"), which amended the Revolving Credit Facility to, among other things:

(i) reaffirm the borrowing base at $100.0 million with next redetermination scheduled for November 2016;
(ii) add a mandatory prepayment provision that requires prepayment of the Revolving Credit Facility (as defined below) by an amount equal to 20% of any future net sales proceeds from the sale of the Company's South STACK Play acreage primarily located in Canadian County, Oklahoma;
(iii) to adjust the minimum interest coverage ratio to: (i) 0.8 to 1.0 for fourth quarter 2016 and first quarter 2017, (ii) 1.0 to 1.0 for second quarter 2017 and (iii) 2.50 to 1.0 thereafter, each as determined using adjusted EBITDA for previous four quarters; and
(iv) to accommodate the Drilling Program (as defined below).

Development Agreement

On October 14, 2016, the Company executed a definitive agreement with STACK Exploration LLC, a Delaware limited liability company, (the "Investor") to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma (the "Development Agreement"). The drilling program (the "Drilling Program") will target the Meramec and Osage formations within the Mississippi Lime on a contract area within three townships covering approximately 18,000 undeveloped net mineral acres under leases held by the Company. The Company will be the operator of all wells jointly developed under the Development Agreement.

Under the Development Agreement, the Investor will fund 90% of Gastar's working interest portion of drilling and completion costs to initially earn 80% of Gastar's working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, Gastar will pay 10% of its working interest portion of such costs for 20% of its original working interest.

The proposed Drilling Program wells will be mutually developed in three tranches of 20 wells each. The locations of the first 20 wells, comprised of 18 Meramec formation wells and two Osage formation wells, have been mutually agreed upon by the Company and the Investor. Participation in the second tranche of 20 Drilling Program wells will be at the election of the Investor and the third tranche of 20 wells will require mutual consent. With respect to each 20 well tranche, when the Investor has achieved an aggregate 15% internal rate of return ("IRR") for its investment in the tranche, its interest will be reduced from 80% to 40% of Gastar's original working interest and Gastar's working interest increases from 20% to 60% of Gastar's original working interest. When a tranche IRR of 20% is achieved by the Investor, its working interest decreases to 10% and Gastar's working interest increases to 90% of the working interest originally owned by Gastar. The parties to the Development Agreement can mutually agree to expand the contract area and drilling formation focus.

Canadian County Property Sale

On October 19, 2016, the Company entered into a purchase and sale agreement to sell certain non-core leasehold interests in approximately 25,300 net acres of which only 19,100 net acres was ascribed allocated value and interests in 25 gross (11.2 net) wells primarily in northeast Canadian County and also in southeast Kingfisher County, Oklahoma to Red Bluff Resources Operating, LLC, a Delaware limited liability company, ("Red Bluff") for approximately $71.0 million (of which up to $10.0 million is contingent upon the satisfaction of certain conditions), subject to certain adjustments. The transaction is expected to close on or before November 18, 2016, with a property sale effective date of August 1, 2016.

Accounts Receivable

Accounts receivable are reported net of the allowance for doubtful accounts. The allowance for doubtful accounts is determined based on a review of the Company's receivables. Receivable accounts are charged off when collection efforts have failed or the account is deemed uncollectible. During the quarter ended June 30, 2016, the Company determined that a receivable account from a third-party natural gas and NGLs purchaser would no longer be collectible as a result of the third-party purchaser filing for bankruptcy. A summary of the activity related to the allowance for doubtful accounts is as follows:

	September 30, 2016	December 31, 2015
	(in thousands)	
Allowance for doubtful accounts, beginning of period	$ —	$ —
Expense	—	—
Reductions/write-offs	1,953	—
Allowance for doubtful accounts, end of period	$ 1,953	$ —

Recent Accounting Developments

The following recently issued accounting pronouncements may impact the Company in future periods:

Statement of Cash Flows. In August 2016, the FASB issued updated guidance associated with the classification of certain cash receipts and cash payments on the statement of cash flows. The amended guidance addresses specific cash flow issues with the objective of reducing existing diversity in practice. The amendments in this update apply to all entities required to present a statement of cash flows. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. Amendments should be applied using a retrospective transition method to each period presented. If it is impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of the earliest date practicable. The Company has not yet determined what the effects of adopting this updated guidance will be on its statement of cash flows.

Compensation – Stock Compensation. In March 2016, the FASB issued updated guidance as part of its simplification initiative which is intended to simplify several aspects of the accounting for stock-based compensation transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. For public business entities, the amendments in this update are effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for any entity in any interim or annual period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. Amendments related to the timing of when excess tax benefits are recognized, minimum statutory withholding requirements, forfeitures, and intrinsic value should be applied using a modified retrospective transition method by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. Amendments related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement should be applied retrospectively. Amendments requiring recognition of excess tax benefits and tax deficiencies in the income statement and the practical expedient for estimating expected term should be applied prospectively. An entity may elect to apply the amendments related to the presentation of excess tax benefits on the statement of cash flows using either a prospective transition method or a retrospective transition method. The Company has not yet determined what the effects of adopting this updated guidance will be on its consolidated financial statements.

Leases. In February 2016, the FASB issued updated guidance to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and enhance disclosures regarding key information about leasing arrangements. Under the new guidance, lessees will be required to recognize a lease liability and a right-of-use asset for all leases. The new lease guidance also simplified the accounting for sale and leaseback transactions primarily because lessees must recognize lease assets and lease liabilities. The amendments in this update are effective beginning on January 1, 2019 and should be applied through a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. Early adoption is permitted. The Company has not yet determined what the effects of adopting this updated guidance will be on its consolidated financial statements.

Income Taxes. In November 2015, the FASB issued updated guidance as part of its simplification initiative for the presentation of deferred taxes. Current U.S. GAAP requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position where such classification generally does not align with the time period in which the recognized deferred tax amounts are expected to be recovered or settled. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position and apply to all entities that present a classified statement of financial position, resulting in the alignment of the U.S. GAAP presentation of deferred income tax assets and liabilities with International Financial Reporting Standards (IFRS). IAS 1, Presentation of Financial Statements. This guidance is effective for public business entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted as of the beginning of an interim or annual reporting period and can be applied either prospectively or retrospectively to all periods presented. The Company does not expect the adoption of this guidance to materially impact its consolidated financial statements.

Going Concern. In August 2014, the FASB issued updated guidance related to determining whether substantial doubt exists about an entity's ability to continue as a going concern. The amendment provides guidance for determining whether conditions or events give rise to substantial doubt that an entity has the ability to continue as a going concern within one year following the date of issuance of annual and interim financial statements, and requires specific disclosures regarding the conditions or events leading to substantial doubt. The updated guidance is effective for annual reporting periods ending after December 15, 2016 and for annual periods and interim periods thereafter. Earlier adoption is permitted, but the Company has not elected to adopt the updated guidance early. The Company does not expect the adoption of this guidance to have a material impact on its consolidated financial statements.

Revenue Recognition. In May 2014, the FASB issued an amendment to previously issued guidance regarding the recognition of revenue, which supersedes the revenue recognition requirements in Accounting Standards Codification (“ASC”) Topic 605, “Revenue Recognition,” and most industry-specific guidance. The FASB and the International Accounting Standards Board initiated a joint project to clarify the principles for recognizing revenue and to develop a common standard that would (i) remove inconsistencies and weaknesses in revenue requirements, (ii) provide a more robust framework for addressing revenue issues, (iii) improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets, (iv) provide more useful information to users of financial statements through improved disclosure requirements and (v) simplify the preparation of financial statements by reducing the number of requirements to which an entity must refer. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, an entity should apply the following steps: (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This guidance supersedes prior revenue recognition requirements and most industry-specific guidance throughout the FASB Accounting Standards Codification. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In April 2015, the FASB proposed to delay the effective date one year, beginning in fiscal year 2018 and such proposal was subsequently adopted by the FASB in August 2015. The Company is evaluating the new guidance and has not yet determined the impact this new standard may have on its consolidated financial statements or decided upon its method of adoption.

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., located in the states of Oklahoma, Pennsylvania and West Virginia. On April 8, 2016, the Company sold substantially all of its producing assets and proved reserves and a significant portion of its undeveloped acreage in Pennsylvania and West Virginia comprising the Company’s Appalachian Basin assets.

The following table summarizes the components of unproved properties excluded from amortization at the dates indicated:

	September 30, 2016	December 31, 2015

	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$10,346	$ 1,533
Acreage acquisition costs	92,299	82,560
Capitalized interest	6,622	8,516
Total unproved properties excluded from amortization	$109,267	$ 92,609

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 (discounted at 10% per annum) 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 at the end of the reported period, the excess must be written off to expense for such period. 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 is determined using a mandatory trailing 12-month unweighted arithmetic average of the first-day-of-the-month commodities pricing and costs in effect at the end of the period, each of which are held constant indefinitely (absent specific contracts with respect to future prices and costs) 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 commodities prices are adjusted for basis and quality differentials in determining the present value of the proved 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:

	2016 Total Year to Date Impairment	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$ 2.28	$2.24	$ 2.40
West Texas Intermediate oil price (per Bbl)(1)		$ 41.68	$43.12	$ 46.26
Impairment recorded (pre-tax) (in thousands)	$48,497	$ —	$—	$ 48,497

	2015 Total Year to Date Impairment	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$3.06	$3.39	$ 3.88
West Texas Intermediate oil price (per Bbl)(1)		$59.21	$71.68	$ 82.72
Impairment recorded (pre-tax) (in thousands)	$282,118	$181,966	$100,152	$ —

(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 spot natural gas prices and West Texas Intermediate spot oil prices.

The Company could potentially incur further ceiling test impairments in 2016 should commodities prices decline. However, it is difficult to project future impairment charges in light of numerous variables involved.

The Company's proved reserves estimates and their estimated discounted value and standardized measure will also be impacted by changes in lease operating costs, future development costs, production, exploration and development activities. The ceiling limitation calculation is not intended to be indicative of the fair market value of the Company's proved reserves or future results.

Development Agreement

On October 14, 2016, the Company executed the Development Agreement with the Investor to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma. The Drilling Program will target the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 18,000 undeveloped net mineral acres under leases held by the Company. The Company will be the operator of all wells jointly developed under the Development Agreement.

Under the Development Agreement, the Investor will fund 90% of Gastar's working interest portion of drilling and completion costs to initially earn 80% of Gastar's working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, Gastar will pay 10% of its working interest portion of such costs for 20% of its original working interest.

The proposed Drilling Program wells will be mutually developed in three tranches of 20 wells each. The locations of the first 20 wells, comprised of 18 Meramec formation wells and two Osage formation wells, have been mutually agreed upon by the Company and the Investor. Participation in the second tranche of 20 Drilling Program wells will be at the election of the Investor and the third tranche of 20 wells will require mutual consent. With respect to each 20 well tranche, when the Investor has achieved an aggregate 15% IRR for its investment in the tranche, its interest will be reduced from 80% to 40% of Gastar’s original working interest and Gastar’s working interest increases from 20% to 60% of Gastar’s original working interest. When a tranche IRR of 20% is achieved by the Investor, its working interest decreases to 10% and Gastar’s working interest increases to 90% of the working interest originally owned by Gastar. The parties to the Development Agreement can mutually agree to expand the contract area and drilling formation focus.

Canadian County Property Sale

On October 19, 2016, the Company entered into a purchase and sale agreement to sell certain non-core leasehold interests in approximately 25,300 net acres of which only 19,100 net acres was ascribed allocated value and interests in 25 gross (11.2 net) wells primarily in northeast Canadian County and also in southeast Kingfisher County, Oklahoma to Red Bluff for approximately $71.0 million (of which up to $10.0 million is contingent upon the satisfaction of certain conditions), subject to certain adjustments. The transaction is expected to close on or before November 18, 2016, with a property sale effective date of August 1, 2016.

Appalachian Basin Sale

On February 19, 2016, the Company entered into an agreement to sell substantially all of its producing assets and proved reserves and a significant portion of its undeveloped acreage in the Appalachian Basin for $80.0 million, subject to customary closing adjustments. Pursuant to the agreement, on April 8, 2016, the Company completed the Appalachian Basin Sale for an adjusted sales price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer. The Appalachian Basin Sale is reflected as a reduction to the full cost pool and the Company did not record a gain or loss related to the divestiture as it was not determined to be significant to the full cost pool and did not result in a significant change to the depletion rate.

Appalachian Basin Sale Pro Forma Operating Results

The following unaudited pro forma results for the three months ended September 30, 2015 and the nine months ended September 30, 2016 and 2015 show the effect on the Company's consolidated results of operations as if the Appalachian Basin Sale had occurred at the beginning of the periods presented. The pro forma results are the result of excluding from the statement of operations of the Company the revenues and direct operating expenses for the properties divested adjusted for (1) the reduction in ARO liabilities and accretion expense for the properties divested, (2) the reduction in depreciation, depletion and amortization expense as a result of the divestiture and (3) the reduction in interest expense as a result of the pay down of debt under the Revolving Credit Facility in conjunction with the closing of the Appalachian Basin Sale. As a result, certain estimates and judgments were made in preparing the pro forma adjustments.

	For the Three Months Ended September 30, 2015 (in thousands, except per share data) (Unaudited)
Revenues	$ 26,847
Net Loss	$ (188,685)
Loss per share:	
Basic	$ (2.43)
Diluted	$ (2.43)

	For the Nine Months Ended September 30,	
	2016	2015
	(in thousands, except per share data) (Unaudited)	
Revenues	$36,892	$73,515
Net Loss	$(90,336)	$(310,148)
Loss per share:		
Basic	$(0.87)	$(4.00)

Diluted	$(0.87)	$(4.00)

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 Appalachian Basin Sale occurred as presented. In addition, future results may vary significantly from the results reflected in such pro forma information.

Husky Acquisition

On December 16, 2015, the Company completed the acquisition of additional working and net revenue interests in 103 gross (10.2 net) producing wells and certain undeveloped acreage in the STACK Play and Hunton limestone formations in its existing AMI from its AMI co-participant Husky Ventures, Inc. (“Husky”), Silverstar of Nevada, Inc., Maximus Exploration, LLC and Atwood Acquisitions, LLC for an adjusted purchase price of approximately $42.7 million, net of $358,000 of revenue suspense liability assumed by the Company, reflecting adjustment for an acquisition effective date of July 1, 2015 and which includes a $715,000 deposit into escrow pending the resolution of title defects by the seller recorded to other assets at September 30, 2016, and the conveyance of approximately 11,000 net non-core, non-producing acres in Blaine, Major and Kingfisher Counties, Oklahoma to the sellers, subject to certain adjustments and customary closing conditions (the "Husky Acquisition"). In connection with the acquisition, the AMI participation agreements with the Company's AMI co-participant were dissolved.

The Company accounted for the acquisition as a business combination and therefore, recorded the assets acquired at their estimated acquisition date fair values. The Company incurred a total of $1.5 million of transaction and integration costs associated with the acquisition since closing and expensed these costs as incurred as general and administrative expenses. The Company utilized relevant market assumptions to determine fair value and allocate the purchase price, such as future commodity prices, projections of estimated natural gas and oil reserves, expectations for future development and operating costs, projections of future rates of production, expected recovery rates and market multiples for similar transactions. Many of the assumptions used are unobservable and as such, represent Level 3 inputs under the fair value hierarchy as described in Note 5, "Fair Value Measurements." The Company's preliminary assessment of the fair value of the Husky Acquisition assets resulted in a fair market valuation of $44.6 million. As the fair market valuation varied less than 6% from the purchase price allocation recorded, no adjustment was made to the purchase price allocation.

Husky Acquisition Pro Forma Operating Results

The following unaudited pro forma results for the three and nine months ended September 30, 2015 show the effect on the Company's consolidated results of operations as if the Husky Acquisition had occurred at the beginning of the period presented. The pro forma results are the result of combining the statement of operations of the Company with the statements of revenues and direct operating expenses for the properties acquired from Husky adjusted for (1) assumption of ARO liabilities and accretion expense for the properties acquired and (2) 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 Husky Acquisition assets exclude all other historical expenses of Husky. As a result, certain estimates and judgments were made in preparing the pro forma adjustments.

	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2015
	(in thousands, except per share data)	
	(Unaudited)	
Revenues	$30,087	$91,493
Net Loss	$(191,256)	$(309,921)
Loss per share:		
Basic	$(2.46)	$(4.00)
Diluted	$(2.46)	$(4.00)

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 Husky Acquisition occurred as presented. Further, the above pro forma amounts do not consider any potential synergies or integration costs that may result from the transaction. In addition, future results may vary significantly from the results reflected in such pro forma information.

4. Long-Term Debt

Second Amended and Restated Revolving Credit Facility

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

The Revolving Credit Facility will be guaranteed by all of the Company's future domestic subsidiaries formed during the term of the Revolving Credit Facility. Borrowings and related guarantees are secured by a first priority lien on certain 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 capital stock of each domestic subsidiary, a first priority interest on all accounts receivable, notes receivable, inventory, contract rights, general intangibles and material property of the issuer and 65% of the stock of any foreign subsidiary of the Company.

The Revolving Credit Facility contains various covenants, including, among others:

- Restrictions on liens, incurrence of other indebtedness without lenders' consent and common stock dividends and other restricted payments;
- Maintenance of a minimum consolidated current ratio as of the end of each quarter of not less than 1.0 to 1.0, as adjusted;
- Maintenance of a maximum ratio of net indebtedness to EBITDA of not greater than 4.0 to 1.0, subject to the modifications in Amendment No. 8 set forth below; and
- Maintenance of an interest coverage ratio on a rolling four quarters basis, as adjusted, of EBITDA to interest expense, as of the end of each quarter, to be less than 2.5 to 1.0, subject to the modifications in Amendment No. 8 set forth below.

All outstanding amounts owed become due and payable upon the occurrence of certain usual and customary events of default, including, among others:

- Failure to make payments;
- Non-performance of covenants and obligations continuing beyond any applicable grace period; and
- The occurrence of a change in control of the Company, as defined under the Revolving Credit Facility.

On December 22, 2015, the Company, together with the parties thereto, entered into Amendment No. 6 to Second Amended and Restated Credit Agreement ("Amendment No. 6"). Amendment No. 6 amended the Revolving Credit Facility to permit the Company to exchange its outstanding Notes constituting Second Lien Debt under the Revolving Credit Facility for equity interests in the Company.

On January 29, 2016, the Company, together with the parties thereto, entered into Limited Waiver and Amendment No. 7 to Second Amended and Restated Credit Agreement ("Amendment No. 7"). Pursuant to Amendment No. 7, the Company obtained (i) a waiver until March 10, 2016 of any potential defaults at December 31, 2015 of its leverage ratio and senior secured leverage ratio under the Revolving Credit Facility and (ii) a permanent waiver of any defaults of the restricted payment covenant under the Revolving Credit Facility resulting from (a) cash distributions paid on December 31, 2015 in respect of its Series A Preferred Stock and its Series B Preferred Stock and (b) the issuance on January 28, 2016, as a dividend on the Company' common stock, of the right to purchase Series C Junior Participating Preferred Stock pursuant to the Company's Rights Agreement dated as of January 18, 2016 (the "Rights Agreement") as part of the Company's previously disclosed tax benefits preservation plan. The Revolving Credit Facility was also amended to permit the Company to make dividends and distributions of preferred equity interests or rights to purchase certain preferred equity interests. The entry into Amendment No. 7 permitted the Company to pay monthly cash dividends on its Series A Preferred Stock and its Series B Preferred Stock on February 1, 2016.

On March 9, 2016, the Company, together with the parties thereto, entered into Waiver and Amendment No. 8 to Second Amended and Restated Credit Agreement ("Amendment No. 8"). Pursuant to Amendment No. 8, the Company obtained the following relief with respect to its financial covenant compliance:

(i) a permanent waiver of the defaults at December 31, 2015 of its leverage ratio and senior secured leverage ratio under the Revolving Credit Facility;
(ii) relief from compliance with its leverage ratio through the fiscal quarter ending March 31, 2017, but the Company must maintain a maximum leverage ratio of not greater than 4.0 to 1.0 for each fiscal quarter ending on or after June 30, 2017;
(iii) an adjustment to the interest coverage ratio for each fiscal quarter ending on or after June 30, 2016 but prior to June 30, 2017, to 1.10 to 1.00 and for each fiscal quarter ending on or after June 30, 2017 to 2.50 to 1.00; and
(iv) an adjustment to its senior secured leverage ratio for each fiscal quarter ending on or after June 30, 2016 but prior to June 30, 2017, to 2.50 to 1.00 provided that during such period the Company may subtract all cash on hand in

calculating the senior secured leverage ratio for such periods and for each fiscal quarter ending on or after June 30, 2017, to 2.00 to 1.00 provided that during such period the Company may only subtract up to $5 million of cash on hand in calculating the senior secured leverage ratio for such periods.

As consideration for the financial covenant relief provided for in Amendment No. 8, the Revolving Credit Facility was also amended to, among other things:

(i) set the interest margin at (a) 4.0% per annum for Eurodollar rate borrowings and (b) 3.0% per annum for borrowings based on the reference rate;
(ii) reduce the borrowing base from $200.0 million to $180.0 million until the earlier of the closing of the Appalachian Basin Sale or April 10, 2016, at which point the borrowing base would automatically be reduced to $100.0 million and require borrowings in excess of such amount be repaid immediately;
(iii) require additional automatic reductions of the borrowing base in connection with asset sales in excess of $5.0 million or the termination of any hedge agreements governing hedges with a settlement date on or after July 1, 2016;
(iv) provide for an additional interim borrowing base redetermination in August 2016;
(v) require the consent of the lenders to any asset sales in excess of $5.0 million; and
(vi) restrict the Company after March 2016 from making any distributions or paying any cash dividends to the holders of its preferred equity, including its outstanding shares of Series A Preferred Stock and Series B Preferred Stock.

On October 14, 2016, the Company, together with the parties thereto, entered into Amendment No. 9, which amended the Revolving Credit Facility to, among other things:

(i) reaffirm the borrowing base at $100.0 million with next redetermination scheduled for November 2016;
(ii) add a mandatory prepayment provision that requires prepayment of the Revolving Credit Facility by an amount equal to 20% of any future net sales proceeds from the sale of the Company's South STACK Play acreage primarily located in Canadian County, Oklahoma;
(iii) to adjust the minimum interest coverage ratio to: (i) 0.8 to 1.0 for fourth quarter 2016 and first quarter 2017, (ii) 1.0 to 1.0 for second quarter 2017 and (iii) 2.50 to 1.0 thereafter, each as determined using adjusted EBITDA for previous four quarters; and
(iv) to accommodate the Drilling Program.

Borrowing base redeterminations are scheduled semi-annually in May and November of each calendar year. The Company and its lenders may each request one additional unscheduled redetermination during any six-month period between scheduled redeterminations. The next borrowing base redetermination is scheduled for November 2016. In connection with Amendment No. 8 and in conjunction with the closing of the Appalachian Basin Sale, the borrowing base was reduced from $180.0 million to $100.0 million on April 8, 2016. The borrowing base was reaffirmed at $100.0 million on October 14, 2016 in connection with Amendment No. 9. At September 30, 2016, the Revolving Credit Facility had a borrowing base of $100.0 million, with $99.6 million borrowings outstanding and $370,000 of letters of credit issued under the Revolving Credit Facility. As of November 1, 2016, there were $99.6 million borrowings outstanding and $370,000 of letters of credit issued under the Revolving Credit Facility. 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 indenture pursuant to which the Company's senior secured notes are issued (as discussed below in "Senior Secured Notes").

On May 10, 2016, the requisite lenders under the Second Amended and Restated Credit Agreement permanently waived an unintended technical default under the Revolving Credit Facility resulting from the timing of the last monthly cash dividend payments made by the Company in March 2016 on the Company's two outstanding classes of preferred stock.

At September 30, 2016, the Company was in compliance with all financial covenants under the Revolving Credit Facility.

Senior Secured Notes

The Company has $325.0 million aggregate principal amount of 8.625% Senior Secured Notes due May 15, 2018 (the "Notes") outstanding under an indenture (the "Indenture") by and among the Company, the Guarantors named therein (the "Guarantors"), Wells Fargo Bank, National Association, as Trustee (in such capacity, the "Trustee") and Collateral Agent (in such capacity, the “Collateral Agent”). The Notes bear interest at a rate of 8.625% per year, payable semi-annually in arrears on May 15 and November 15 of each year. The Notes mature on May 15, 2018. Effective May 17, 2016, Wells Fargo Bank, National Association resigned as Trustee and Collateral Agent and Wilmington Trust was appointed Trustee and Collateral Agent pursuant to the Indenture.

In the event of a change of control, as defined in the Indenture, each holder of the Notes 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 guaranteed, jointly and severally, on a senior secured basis by 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.

Covenants in the Indenture also limit the Company's ability to borrow on a first priority lien secured basis, including its ability to refinance the full amount of currently outstanding borrowings under its Revolving Credit Facility or to re-borrow on such facility in the event current borrowings thereunder are paid down. These and other covenants that are contained in the Indenture are subject to important limitations and qualifications that are described in the Indenture.

A summary of the Notes balance for the periods indicated is as follows:

	September 30, 2016	December 31, 2015
	(in thousands)	
Notes, principal balance	$325,000	$325,000
Less:		
Unamortized discounts	(5,070)	(7,151)
Deferred financing costs	(940)	(1,373)
Notes, net	$318,990	$316,476

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. There was no impairment of unproved properties for the three months ended September 30, 2016 and 2015. For the nine months ended September 30, 2016 and 2015, respectively, due to continued lower natural gas prices for dry gas and no current plans to drill or extend leases in Marcellus East, management's evaluation of unproved properties resulted in impairment and the Company reclassified an immaterial amount of costs from unproved to proved properties for each period. As no other fair value measurements are required to be recognized on a non-recurring basis at September 30, 2016, no additional disclosures are provided at September 30, 2016.

As defined in the guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ("Level 1") and the lowest priority to unobservable inputs ("Level 3"). The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities. The Company's cash equivalents consist of short-term, highly liquid investments, which have maturities of 90 days or less, including sweep investments and money market funds.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources. These inputs may be used with internally developed methodologies or third party broker quotes that result in management's best estimate of fair value. The Company's valuation models consider various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Level 3 instruments are commodity costless collars, index swaps, basis and fixed price swaps and put and call options to hedge natural gas, oil and NGLs price risk. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs. The fair values derived from counterparties and third-party brokers are verified by the Company using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its 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 2016 and 2015 periods.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2016 and December 31, 2015:

	Fair value as of September 30, 2016	
	Level 1	Total

		Level 2	Level 3	
	(in thousands)			
Assets:				
Cash and cash equivalents	$46,739	$ —	$—	$46,739
Commodity derivative contracts	—	—	9,155	9,155
Liabilities:				
Commodity derivative contracts	—	—	(102)	(102)
Total	$46,739	$ —	$9,053	$55,792

	Fair value as of December 31, 2015			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$50,074	$ —	$—	$50,074
Commodity derivative contracts	—	—	24,869	24,869
Liabilities:				
Commodity derivative contracts	—	—	(451)	(451)
Total	$50,074	$ —	$24,418	$74,492

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, 2016 and 2015. 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, 2016 and 2015.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Balance at beginning of period	$12,782	$22,373	$24,418	$27,502
Total (losses) gains included in earnings	(1,498)	11,301	(3,991)	19,734
Purchases	—	415	565	1,326
Issuances	—	—	(165)	(1,313)
Settlements[(1)]	(2,231)	(6,793)	(11,774)	(19,953)
Balance at end of period	$9,053	$27,296	$9,053	$27,296
The amount of total (losses) gains for the period included in earnings attributable to the change in mark to market of commodity derivatives contracts still held at September 30, 2016 and 2015	$(3,134)	$4,511	$(12,974)	$986

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

At September 30, 2016, 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, 2016 was $366.3 million based on quoted market prices of the Notes (Level 1) and the respective carrying value of the Revolving Credit Facility because the interest rate approximates the current market rate (Level 2).

The Company has consistently applied the valuation techniques discussed above in all periods presented.

The fair value guidance, as amended, establishes that every derivative instrument is to be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 6, "Derivative Instruments and Hedging Activity."

6. Derivative Instruments and Hedging Activity

The Company maintains a commodity price risk management strategy that uses derivative instruments to minimize significant, unanticipated earnings fluctuations that may arise from volatility in commodity prices. The Company uses costless collars, index, basis and fixed price swaps and put and call options to hedge 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, 2016 and 2015, the Company reported a loss of $3.1 million and a gain of $4.5 million, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts still held at September 30, 2016 and 2015. For the nine months ended September 30, 2016 and 2015, the Company reported a loss of $13.0 million and a gain of $986,000, respectively, in the condensed consolidated statements of operations related to the change in the fair value of its commodity derivative contracts still held at September 30, 2016 and 2015.

As of September 30, 2016, 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 (in Bbls)	Total of Notional Volume(1)	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
2016	Costless three-way collar	250	30,500	$—	$85.00	$65.00	$95.10
2016	Costless three-way collar	330	40,260	$—	$80.00	$65.00	$97.35
2016	Costless three-way collar	450	54,900	$—	$57.50	$42.50	$80.00
2016	Put spread	550	67,100	$—	$85.00	$65.00	$—
2016	Fixed price swap	300	36,600	$56.30	$—	$—	$—
2016	Fixed price swap	200	24,400	$50.00	$—	$—	$—
2017	Costless three-way collar	280	102,200	$—	$80.00	$65.00	$97.25
2017	Costless three-way collar	250	91,250	$—	$80.00	$60.00	$98.70
2017(2)	Protective spread	200	36,200	$60.00	$—	$42.50	$—
2017	Put spread	500	182,500	$—	$82.00	$62.00	$—
2017(2)	Protective spread	200	36,200	$57.50	$—	$42.50	$—
2017(2)	Fixed price swap	300	54,300	$50.10	$—	$—	$—
2017(3)	Costless three-way collar	200	36,800	$—	$60.00	$42.50	$85.00
2017(3)	Costless three-way collar	200	36,800	$—	$57.50	$42.50	$76.13
2017(4)	Fixed price swap	200	18,000	$50.05	$—	$—	$—
2018(5)	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 2017.
(3) For the period July to December 2017.
(4) For the period January to March 2017.
(5) For the period January to August 2018.

As of September 30, 2016, 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	Floor (Long)	Short Put	Ceiling (Short)
2016(1)	Costless three-way collar	2,500	77,500	$ 3.00	$2.25	$ 3.65
2016	Costless three-way collar	2,000	184,000	$ 4.00	$3.25	$ 4.58
2016	Costless three-way collar	5,000	460,000	$ 3.40	$2.65	$ 4.10

2017	Costless three-way collar	5,000	1,825,000	$ 3.00	$ 2.35	$ 4.00
2017(2)	Costless collar	2,000	180,000	$ 3.10	$—	$ 3.78
2018	Costless three-way collar	5,000	1,825,000	$ 3.00	$ 2.35	$ 4.00

(1) For the month of October 2016.
(2) For the period January to March 2017.

As of September 30, 2016, the following NGLs derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume	Total of Notional Volume	Base Fixed Price
		(in Bbls)		
2016	Fixed price swap	500	61,000	$ 20.79

As of September 30, 2016, all of the Company's economic derivative hedge positions were with 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 has deferred the payment of certain put premiums for the production month period October 2016 through December 2018. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company amortizes the deferred put premium liabilities as they become payable. The following table provides information regarding the deferred put premium liabilities for the periods indicated:

	September 30, 2016	December 31, 2015
	(in thousands)	
Current commodity derivative put premium payable	$ 1,750	$ 3,194
Long-term commodity derivative put premium payable	1,427	2,788
Total unamortized put premium liabilities	$ 3,177	$ 5,982

	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2016
	(in thousands)	
Put premium liabilities, beginning balance	$ 3,546	$ 5,982
Settlement of put premium liabilities	(369)	(2,640)
Additional put premium liabilities	—	(165)
Put premium liabilities, ending balance	$ 3,177	$ 3,177

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of September 30, 2016:

	Amortization (in thousands)
October to December 2016	$ 554
January to December 2017	1,654
January to August 2018	969
Total unamortized put premium liabilities	$ 3,177

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)		
		Fair Value	
	Balance Sheet Location	September 30, 2016	December 31, 2015
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$5,240	$ 15,534
Commodity derivative contracts	Other assets	3,915	9,335
Commodity derivative contracts	Current liabilities	(102)	—
Commodity derivative contracts	Long-term liabilities	—	(451)
Total derivatives not designated as hedging instruments		$9,053	$ 24,418

	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Three Months Ended September 30, 2016	2015
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	(Loss) gain on commodity derivatives contracts	$(1,498)	$11,301
Total		$(1,498)	$11,301

	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives For the Nine Months Ended September 30, 2016	2015
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	(Loss) gain on commodity derivatives contracts	$(3,991)	$19,734
Total		$(3,991)	$19,734

7. Capital Stock

Common Stock

On May 7, 2015, the Company entered into an at-the-market issuance sales agreement with MLV & Co. LLC (the "Sales Agent") to sell, from time to time through the Sales Agent, shares of the Company's common stock (the "ATM Program"). The shares will be issued pursuant to the Company's existing effective shelf registration statement on Form S-3, as amended (Registration No. 333-193832). The Company registered shares having an aggregate offering price of up to $50.0 million. To date, no shares have been sold through the ATM Program.

On May 12, 2016, the Company sold 50,000,000 shares of its common stock in an underwritten public offering at a price of $0.95 per share, or $47.5 million before offering costs and expenses (the "Equity Offering"). The Company received approximately $44.8 million of proceeds from the offering, net of offering costs and expenses of approximately $2.7 million.

On June 14, 2016, the Company's stockholders approved an amendment to the Company's certificate of incorporation to increase the number of authorized shares of common stock from 275,000,000 to 550,000,000, which amendment became effective on July 5, 2016.

Stockholder Rights Agreement

On January 18, 2016, the Company's Board of Directors adopted the Rights Agreement pursuant to which the Company declared a dividend of one right (a "Right") for each of the Company's issued and outstanding shares of common stock. The dividend was paid to stockholders of record on January 28, 2016. Each Right entitles the holder, subject to the terms of the Rights Agreement, to purchase one one-thousandth of a share of the Company's Series C Junior Participating Preferred Stock (the "Series C Preferred Stock") at a price of $6.96, subject to certain adjustments. The purpose of the Rights Agreement is to diminish the risk that the Company's ability to reduce potential future federal income tax obligations would become subject to limitations by reason of an "ownership change," as defined in Section 382 of the Internal Revenue Code of 1986, as amended.

The Rights generally become exercisable on the earlier of (i) ten business days after any person or group obtains beneficial ownership of 4.9% of the Company's outstanding common stock (an "Acquiring Person") or (ii) ten business days after commencement of a tender or exchange offer resulting in any person or group becoming an Acquiring Person. The exercise price payable, and the number of shares of Series C Preferred Stock or other securities or property issuable, upon exercise of the Rights are subject to adjustment from time to time to prevent dilution. In the event that, after a person or a group has become an Acquiring Person, the Company is acquired in a merger or other business combination transaction (or 50% or more of the Company's assets or earning power are sold), proper provision will be made so that each holder of a Right will thereafter have the right to receive, upon the exercise thereof at the then-current exercise price of the Right, that number of shares of common stock of the acquiring company having a market value at the time of that transaction equal to two times the exercise price.

The Company may redeem the Rights in whole, but not in part, at any time before a person or group becomes an Acquiring Person at a price of $0.001 per Right, subject to adjustment. At any time after any person or group becomes an Acquiring Person, the Company may generally exchange each Right in whole or in part at an exchange ratio of two shares of common stock per outstanding Right, subject to adjustment. The Rights will expire on January 18, 2019 unless terminated on an earlier date pursuant to the terms of the Rights Agreement.

The Series C Preferred Stock is not redeemable by the Company and has certain voting rights and dividend and liquidation privileges.

The Rights Agreement was amended on May 11, 2016 to make certain provisions inapplicable to purchasers of the Equity Offering who are approved by the board of directors of the Company, or a committee thereof, so that no such purchaser will be deemed an “Acquiring Person” under the Rights Agreement by virtue of their purchase of common stock in the Equity Offering.

Preferred Stock

Pursuant to the Company’s certificate of incorporation, the Company has 40,000,000 shares of preferred stock authorized. The Company has designated 10,000,000 of such shares to constitute its 8.625% Series A Cumulative Preferred Stock (the “Series A Preferred Stock”) and 10,000,000 of such shares to constitute its 10.75% Series B Cumulative Preferred Stock (the “Series B Preferred Stock”). The Series A Preferred Stock and the Series B Preferred Stock each have a par value of $0.01 per share and a liquidation preference of $25.00 per share.

Series A Preferred Stock

At September 30, 2016, there were 4,045,000 shares of the Series A Preferred Stock issued and outstanding with a $25.00 per share liquidation preference.

The Series A Preferred Stock ranks senior (to the extent of its stated liquidation preference and any accumulated and unpaid dividends) to the Company's common stock and on parity with the Series B Preferred Stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding up. 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 whether declared or not.

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

The Company paid monthly dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference through March 2016. Effective March 9, 2016, the Revolving Credit Facility prohibited the payment of cash dividends on the Company’s preferred stock commencing April 2016. Accordingly, the Company did not declare or pay dividends on the Series A Preferred Stock in April 2016 or any subsequent month. Dividends on the Series A Preferred Stock accumulate regardless of whether any such dividends are declared. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then commencing in the calendar month following the first month in such fourth calendar quarter in which cash dividends are not paid in full, and until accumulated dividends are paid in full for four calendar quarters with the last two calendar quarters’ dividends paid in cash, (i) the fixed dividend rate of Series A Preferred Stock each increases by 2.00% per annum, (ii) the Company may be required to issue a dividend of common stock to pay accrued and unpaid dividends, if such dividends are not paid in cash, provided it has sufficient surplus to pay such a dividend under state law, and (iii) the holders of Series A Preferred Stock and Series B Preferred Stock, voting as a single class, will have the right to elect up to two additional directors to the board of directors of the Company. Under certain circumstances, “pay in kind” dividends of additional shares of Series A Preferred Stock may be payable in lieu of cash or common stock dividends. For the three and nine months ended September 30, 2016, the Company recognized dividends of $2.2 million and $6.6 million, respectively, for the Series A Preferred Stock. Accumulated and unpaid dividends on the outstanding Series A Preferred Stock, which as of September 30, 2016 aggregated $4.4 million, is added to the stated liquidation preference with respect to any preferred distribution of assets upon liquidation, dissolution or winding up.

Series B Preferred Stock

At September 30, 2016, there were 2,140,000 shares of the Series B Preferred Stock issued and outstanding with a $25.00 per share liquidation preference.

The Series B Preferred Stock ranks senior (to the extent of its stated liquidation preference and any accumulated and unpaid dividends) 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, as defined in the Series B Preferred Stock certificate of designations of rights and preferences, 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 ownership or control, the Company will have the option to redeem the Series B Preferred Stock within 90 days of the occurrence of the change in control, 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 the Company's common stock based upon on an average common stock trading price then in effect but limited 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 paid monthly dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference through March 2016. Effective March 9, 2016, the Revolving Credit Facility prohibited the payment of cash dividends on the Company’s preferred stock commencing April 2016. Accordingly, the Company did not declare or pay dividends on the Series B Preferred Stock in April 2016 or any subsequent month. Dividends on the Series B Preferred Stock will accumulate regardless of whether any such dividends are declared. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then commencing in the calendar month following the first month in such fourth calendar quarter in which cash dividends are not paid in full, and until accumulated dividends are paid in full for four calendar quarters with the last two calendar quarters’ dividends paid in cash, (i) the fixed dividend rate of Series B Preferred Stock each increases by 2.00% per annum, (ii) the Company may be required to issue a dividend of common stock to pay accrued and unpaid dividends, if such dividends are not paid in cash, provided it has sufficient surplus to pay such a dividend under state law, and (iii) the holders of Series A Preferred Stock and Series B Preferred Stock, voting as a single class, will have the right to elect up to two additional directors to the board of directors of the Company. Under certain circumstances, “pay in kind” dividends of additional shares of Series B Preferred Stock may be payable in lieu of cash or common stock dividends. For the three and nine months ended September 30, 2016, the Company recognized dividends of $1.4 million and $4.3 million, respectively, for the Series B Preferred Stock. Accumulated and unpaid dividends on the outstanding Series B Preferred Stock, which as of September 30, 2016 aggregated $2.9 million, is added to the stated liquidation preference with respect to any preferred distribution of assets upon liquidation, dissolution or winding up.

No shares of Series C Preferred Stock have been issued by the Company pursuant to the Rights Agreement described above or otherwise.

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, 2016	For the Nine Months Ended September 30, 2016
Other share issuances:		
Shares of restricted common stock granted	—	1,714,645
Shares of restricted common stock vested	33,075	1,472,915
Shares of common stock issued pursuant to PBUs vested, net of forfeitures	—	502,593
Shares of restricted common stock surrendered upon vesting/exercise[(1)]	3,664	389,905
Shares of restricted common stock forfeited	—	126,336

(1) Represents shares of common stock forfeited in connection with the payment of estimated withholding taxes on shares of restricted common stock 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 of common stock reserved for issuance under the LTIP by 3,000,000 shares of common stock. There were 1,636,039 shares of common stock available for issuance under the LTIP at September 30, 2016.

Shares Reserved

At September 30, 2016, the Company had 214,600 common shares reserved for the exercise of stock options.

8. 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,	
	2016	2015	2016	2015
	(in thousands)			
Interest expense:				
Cash and accrued	$8,158	$7,703	$25,275	$22,872
Amortization of deferred financing costs[1]	986	916	3,812	2,652
Capitalized interest	(966)	(686)	(2,348)	(3,094)
Total interest expense	$8,178	$7,933	$26,739	$22,430

(1) The three months ended September 30, 2016 and 2015 includes $711,000 and $644,000, respectively, of debt discount accretion related to the Notes. The nine months ended September 30, 2016 and 2015 includes $2.1 million and $1.9 million, respectively, of debt discount accretion related to the Notes.

9. Income Taxes

For the three and nine months ended September 30, 2016 and 2015, respectively, the Company did not recognize a current income tax benefit or provision as the Company has a full valuation allowance against assets created by net operating losses generated. The Company believes it more likely than not that the assets will not be utilized.

26

10. 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,	
	2016	2015	2016	2015
	(in thousands, except per share and share data)			
Net loss attributable to common stockholders	$(3,796)	$(191,819)	$(95,371)	$(312,837)
Weighted average common shares outstanding - basic	129,301,817	77,628,120	104,125,317	77,453,251
Incremental shares from unvested restricted shares	—	—	—	—
Incremental shares from outstanding stock options	—	—	—	—
Incremental shares from outstanding PBUs	—	—	—	—
Weighted average common shares outstanding - diluted	129,301,817	77,628,120	104,125,317	77,453,251
Net loss per share of common stock attributable to common stockholders:				
Basic	$(0.03)	$(2.47)	$(0.92)	$(4.04)
Diluted	$(0.03)	$(2.47)	$(0.92)	$(4.04)
Common shares excluded from denominator as anti-dilutive:				
Unvested restricted shares	170,362	239,161	540,994	146,253
Unvested PBUs	1,041,493	503,271	837,199	84,179
Total	1,211,855	742,432	1,378,193	230,432

11. Commitments and Contingencies

Litigation

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 was $20.0 million. The District Court granted the underwriters' summary judgment request by a ruling dated January 4, 2012. The Company appealed the District Court ruling and on July 15, 2013. The Fourteenth Court of Appeals of Texas reversed the summary judgment ruling granted against the Company on the basis of the policies' prior-and-pending litigation endorsement and remanded the case for further proceedings in the District Court. The insurers filed a motion for reconsideration in the Fourteenth Court of Appeals, which that court denied. The insurers then sought discretionary review from the Texas Supreme Court, which that court denied on February 27, 2015. The insurers then filed in the Texas Supreme Court a motion for rehearing of their denied petition for review, which the court denied. The case was remanded to the District Court for trial. In October 2015, the Insurers sought a summary judgment based on one of the exclusions in the policy. The trial court denied their motion. After denying the insurers' motion for summary judgment, the trial court, on February 17, 2016, entered a docket control order establishing the week of November 29, 2016 as the tentative week for the case to go to trial. The parties engaged in coverage-related discovery for approximately nine months. On August 10, 2016, Gastar and the insurers settled their coverage dispute for $10.1 million. Insurers' settlement payments to Gastar were paid in September 2016 and were recorded as litigation settlement benefit in the statement of operations at September 30, 2016.

Gastar Exploration Inc. v. Christopher McArthur (Cause No.: 2015-77605) 157th Judicial District Court, Harris County, Texas. On December 29, 2015, Gastar filed suit against Christopher McArthur ("McArthur") in the District Court of Harris County, Texas. The lawsuit arises from a demand letter sent by McArthur to Gastar in which he claimed to be party to an agreement with Gastar that entitled him to be paid $2.75 million for services rendered. In August 2016, McArthur filed an amended answer admitting he had no agreement with the Company. As a result, Gastar believes McArthur's claim has been effectively resolved. Gastar has continued to pursue a counterclaim in this action against McArthur for tortious interference with an existing contract. McArthur has filed a general denial.

Torchlight Energy Resources, Inc., Torchlight Energy, Inc. v. Husky Ventures, Inc., et al., (Cause No. 429-01961-2016) 429th Judicial District Court in Collin County, Texas. Torchlight Energy Resources, Inc. and Torchlight Energy, Inc. (collectively "Torchlight") brought a lawsuit against the Company, two of its executive officers, its chairman of the board of directors and a former director of the Company on May 3, 2016 in Collin County, Texas (the "Torchlight Lawsuit"). The Torchlight Lawsuit arises primarily out of Torchlight's business dealings with Husky in Oklahoma. Husky and several of its employees and affiliates are also defendants in the Torchlight Lawsuit. As part of settlement negotiations between Husky and the Company in a separate lawsuit, Husky informed the Company that it had agreed to repurchase assets from Torchlight that Husky had previously sold to Torchlight (the "Torchlight Assets"). Husky offered to sell those Torchlight Assets to the Company. In the Purchase and Sale Agreement between Torchlight and Husky, Torchlight expressly acknowledged that the Torchlight Assets were to be sold to the Company and released the Company from any claims arising out of the sale of the Torchlight Assets. Despite this release, Torchlight has alleged multiple causes of action against the Company and its officers and directors arising out of the sale of the Torchlight Assets and Torchlight's other business dealings it had with Husky.

The Company has filed a counterclaim against Torchlight for breach of the release in the Purchase and Sale Agreement. Torchlight has dropped their claims, without prejudice, against the former director of the Company, but continues to assert claims against the remaining Gastar defendants.

The Company believes the plaintiffs' claims are without merit and are merely an attempt to induce the Company into settling disputes that are primarily between Torchlight and Husky. The Company intends to defend this case vigorously.

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 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.

12. 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,	
	2016	2015
	(in thousands)	
Cash paid for interest, net of capitalized amounts	$16,140	$12,699
Non-cash transactions:		
Capital expenditures included in (excluded from) accounts payable and accrued drilling costs	$4,913	$(12,396)
Capital expenditures included in accounts receivable	$409	$—
Asset retirement obligation included in oil and natural gas properties	$128	$276
Asset retirement obligation sold	$(694)	$—
Preferred dividends accrued but not declared	$7,237	$—

Application of advances to operators	$(378)	$11,113
Expenses accrued for the issuance of common stock	$2	$—

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements other than statements of historical fact included or incorporated by reference in this report are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, future covenant compliance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “a “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of such terms or variations thereon, other comparable terminology.

The forward-looking statements contained in this 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;
- cash flow and liquidity;
- timing and results of property divestitures;
- compliance with covenants under our indenture and credit agreement;
- business strategy and budgets;
- capital expenditures;
- drilling of wells, including the scheduling and results of such operations;
- oil, natural gas and natural gas liquids (“NGLs”) reserves;
- timing and amount of future production of oil, condensate, natural gas and NGLs;
- operating costs and other expenses;
- availability of capital; and
- prospect development.

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

- the supply and demand for oil, condensate, natural gas and NGLs;
- continued low or further declining prices for oil, condensate, natural gas and NGLs, including risks of low commodity prices affecting the benefits of the Development Agreement;
- our financial condition, results of operations, revenues, cash flows and expenses;
- the potential need to sell certain assets, restructure our debt or raise additional capital;
- the need to take ceiling test impairments due to lower commodity prices;
- worldwide political and economic conditions and conditions in the energy market;
- the extent to which we are able to realize the anticipated benefits from acquired assets;
- our ability to monetize certain assets;
- our ability to raise capital to fund capital expenditures, service our indebtedness or repay or refinance debt upon maturity;

29

- our ability to meet financial covenants under our indenture or credit agreement or the ability to obtain amendments or waivers to effect such compliance;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our co-participants to fund any or all of their portion of any capital program;
- the ability to find, acquire, 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;
- 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 oil and natural gas 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 oil and natural gas.

For a more detailed description of the risks and uncertainties that we face and other factors that could affect our financial performance or cause our actual results to differ materially from our projected results please see (i) Part II, Item 1A. “Risk Factors” and elsewhere in this report, (ii) Part II, Item 1A. “Risk Factors” and elsewhere in our Quarterly Report on Form 10-Q for the quarters ended March 31, 2016 and June 30, 2016, (iii) Part I, Item 1A. “Risk Factors” and elsewhere in our 2015 Form 10-K, (iv) our subsequent reports and registration statements filed from time to time with the SEC and (v) 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 on which they are made to reflect new information, 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 a pure play Mid-Continent independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. We hold a concentrated acreage position in what is believed to be the core of the STACK Play, an area of central Oklahoma which is home to multiple oil and natural gas-rich reservoirs including the Oswego limestone, Meramec and Osage bench formations within the Mississippi Lime, the Woodford shale and Hunton limestone formations. On April 8, 2016, we sold substantially all of our producing assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for an adjusted sales price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer, with an effective date of January 1, 2016 (the "Appalachian Basin Sale").

Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. As of September 30, 2016, our major assets consist of approximately 173,500 gross (105,500 net) acres in Oklahoma (51% undeveloped) and approximately 15,700 gross (14,800 net) acres in West Virginia (83% undeveloped).

The following discussion addresses material changes in our results of operations for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015 and material changes in our financial condition since December 31, 2015. 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 2015 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" of our 2015 Form 10-K.

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 the Mid-Continent area, 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.

We believe that our acreage is prospective in the STACK Play, an area of central Oklahoma that includes oil and natural gas-rich formations such as the Meramec and Woodford Shale, ranging in depth from 6,000 to 9,000 feet, and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec as well as the proven Hunton limestone horizontal oil play. We believe that the STACK Play is one of the most economic plays in North America. It is a horizontal drilling play in an area of previously drilled vertical wells with multiple productive reservoirs that are predominantly oil producing. The STACK Play encompasses all or parts of Blaine, Canadian, Garfield, Kingfisher and Major counties in Oklahoma. STACK is an acronym for Sooner Trend Anadarko Canadian Kingfisher. At September 30, 2016, we held leases covering approximately 173,500 gross (105,500 net) acres in Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the STACK Play.

Our leasing activities primarily located in northwest Kingfisher County, Oklahoma, began in 2012 initially with an AMI co-participant and were expanded to include two additional adjacent prospect areas. Prior to the closing of the Husky Acquisition (as defined below), our AMI co-participant handled all drilling, completion and production activities, and we handled leasing and permitting activities in certain areas of the AMI. On December 16, 2015, we completed the acquisition of additional working and net revenue interests in 103 gross (10.2 net) producing wells and certain undeveloped acreage in the STACK Play and Hunton limestone formations in our existing AMI from our AMI co-participant Husky Ventures, Inc., Silverstar of Nevada, Inc., Maximus Exploration, LLC and Atwood Acquisitions, LLC for an adjusted purchase price of approximately $42.7 million, net of $358,000 of revenue suspense liability assumed by us, reflecting adjustment for an acquisition effective date of July 1, 2015 and which includes a $715,000 deposit into escrow pending the resolution of title defects by the seller recorded to other assets at September 30, 2016, and the conveyance of approximately 11,000 net non-core, non-producing acres in Blaine, Major and Kingfisher Counties, Oklahoma to the sellers, subject to certain adjustments and customary closing conditions (the "Husky Acquisition") and; as a result of the Husky Acquisition, we assumed operatorship of a majority of the acquired wells. With the closing of the Husky Acquisition, our AMI participation agreements with our AMI co-participant were dissolved.

On October 14, 2016, we executed a definitive agreement with STACK Exploration LLC, a Delaware limited liability company, (the "Investor") to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma (the "Development Agreement"). The drilling program (the "Drilling Program") will target the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 18,000 undeveloped net mineral acres under leases held by us. We will be the operator of all wells jointly developed under the Development Agreement.

Under the Development Agreement, the Investor will fund 90% of our working interest portion of drilling and completion costs to initially earn 80% of our working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, we will pay 10% of our working interest portion of such costs for 20% of our original working interest in the well.

The proposed Drilling Program wells will be mutually developed in three tranches of 20 wells each. The locations of the first 20 wells, comprised of 18 Meramec formation wells and two Osage formation wells, have been mutually agreed upon by the Company and the Investor. Participation in the second tranche of 20 Drilling Program wells will be at the election of the Investor and the third tranche of 20 wells will require mutual consent. With respect to each 20 well tranche, when the Investor has achieved an aggregate 15% internal rate of return ("IRR") for its investment in the tranche, its interest will be reduced from 80% to 40% of our original working interest and our working interest increases from 20% to 60% of our original working interest. When a tranche IRR of 20% is achieved by the Investor, its working interest decreases to 10% and our working interest increases to 90% of the working interest originally owned by us. The parties to the Development Agreement can mutually agree to expand the contract area and formation focus.

On October 19, 2016, we entered into a purchase and sale agreement to sell certain non-core leasehold interests in approximately 25,300 net acres of which only 19,100 net acres was ascribed allocated value and interests in 25 gross (11.2 net) wells primarily in northeast Canadian County and also in southeast Kingfisher County, Oklahoma to Red Bluff Resources Operating, LLC, a Delaware limited liability company, ("Red Bluff") for approximately $71.0 million (of which up to $10.0 million is contingent upon the satisfaction of certain conditions), subject to certain adjustments. Current production for the wells included in the sale is approximately 164 barrels of oil equivalent per day. The transaction is expected to close on or before November 18, 2016, with a property sale effective date of August 1, 2016.

As of September 30, 2016 and currently as of the date of this report, we had production and drilling operations at various stages on the following operated STACK wells on our acreage:

				Current Production Average[(3)]			
Well Name	Current Working Interest[(1)]	Approximate Lateral Length (in feet)	Peak Production Rates[(2)] (BOE/d)	BOE/d	% Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Meramec Completions							
Holiday Road 2-1H[(5)]	78.3%	4,300	654	508	75%	April 11, 2016	$ 4.1
Ingle 29-1H[(4)]	82.5%	4,800	N/A	N/A	N/A	October 22, 2016	$ 4.5
Geis 31-1H[(4)]	53.7%	4,600	N/A	N/A	N/A	WOC	$ 4.5
Katy 21-1H[(4)]	67.9%	4,900	N/A	N/A	N/A	WOC	$ 4.5
Lily 28-1H[(4)(5)]	61.3%	4,700	N/A	N/A	N/A	Drilling	$ 4.5
Mott 19-1H[(4)]	44.3%	4,200	N/A	N/A	N/A	Drilling	$ 4.5
Osage Completions							

McGee 29-1H(5)	81.0%	4,200	N/A	N/A	N/A	September 25, 2016	$	4.4
Oswego Completions								
Tomahawk 7-1H	79.3%	4,200	N/A	N/A	N/A	September 24, 2016	$	2.7

(1) Current estimated working interest. Working interest subject to change based on final force pooling orders or Drilling Program activity.
(2) Represents highest daily gross Boe rate. N/A indicates that the well has not yet reached its peak initial production rate.
(3) Represents average gross production for the most current five days through October 26, 2016.
(4) Drilling Program well. Working interest reflected is our total current working interest before Development Agreement impact.
(5) Excludes one-time fishing or coring costs.

To further test the potential of other Mid-Continent STACK Play formations, to date in 2016, we have participated in the completion of four gross (0.5 net) non-operated Meramec Shale wells, one gross (0.2 net) non-operated well targeting the Osage Shale, four gross (0.4 net) non-operated wells targeting the Oswego Limestone formation and one gross (0.04 net) non-operated Woodford Shale wells.

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

Mid-Continent	For the Three Months Ended September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Net Production:				
Oil and condensate (MBbl)	242	274	790	875
Natural gas (MMcf)	997	805	2,917	2,491
NGLs (MBbl)	128	111	380	320
Total net production (MBoe)	537	520	1,656	1,611
Net Daily Production:				
Oil and condensate (MBbl/d)	2.6	3.0	2.9	3.2
Natural gas (MMcf/d)	10.8	8.7	10.6	9.1
NGLs (MBbl/d)	1.4	1.2	1.4	1.2
Total net daily production (MBoe/d)	5.8	5.6	6.0	5.9
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$42.56	$44.45	$37.87	$48.54
Natural gas (per Mcf)	$2.48	$2.67	$2.06	$2.76
NGLs (per Bbl)	$13.22	$10.28	$12.79	$13.16
Average sales price per Boe(1)	$26.98	$29.80	$24.63	$33.27
Selected operating expenses (in thousands):				
Production taxes	$398	$329	$1,154	$1,170
Lease operating expenses(2)	$5,044	$4,328	$15,007	$15,020
Transportation, treating and gathering	$337	$3	$730	$10
Selected operating expenses per Boe:				
Production taxes	$0.74	$0.63	$0.70	$0.73
Lease operating expenses(2)	$9.40	$8.33	$9.06	$9.32
Transportation, treating and gathering	$0.63	$0.01	$0.44	$0.01
Production costs(3)	$10.03	$8.34	$9.50	$9.33

(1) Excludes the impact of hedging activities.
(2) Lease operating expenses for the three and nine months ended September 30, 2016 include $592,000 and $1.4 million, respectively, of workover expense for production enhancing WEHLU well workovers. Lease operating expenses for the three and nine months ended September 30, 2015 include $1.1 million and $3.8 million, respectively, of workover expense for production enhancing WEHLU workovers. Excluding workover expense, lease operating expense per Boe for the three and nine months ended September 30, 2016 would have been $8.30 per Boe and $8.20 per Boe, respectively, compared to $6.23 per Boe and $6.94 per Boe for the three and nine months ended September 30, 2015, respectively.
(3) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Appalachian Basin.

Due to the continued depressed price environment in the Appalachian Basin, we suspended our drilling operations in the Appalachian Basin in the second quarter of 2015. On April 8, 2016, we sold substantially all of our producing assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for an adjusted price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer. As of September 30, 2016, our acreage position in the play was approximately 15,700 gross (14,800 net) acres, 83% of which is undeveloped, in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia.

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

Appalachian Basin	For the Three Months Ended September 30, 2016[(1)]	2015	For the Nine Months Ended September 30, 2016[(1)]	2015
Net Production:				
Oil and condensate (MBbl)	—	56	47	191
Natural gas (MMcf)	12	2,685	2,315	7,869
NGLs (MBbl)	—	226	236	533
Total net production (MBoe)	2	730	669	2,035
Net Daily Production:				
Oil and condensate (MBbl/d)	—	0.6	0.2	0.7
Natural gas (MMcf/d)	0.1	29.2	8.4	28.8
NGLs (MBbl/d)	—	2.5	0.9	2.0
Total net daily production (MBoe/d)	—	7.9	2.4	7.5
Average sales price per unit [(2)]:				
Oil and condensate (per Bbl)	$—	$11.64	$11.73	$17.24
Natural gas (per Mcf)	$2.10	$0.49	$1.03	$0.92
NGLs (per Bbl)	$—	$(1.56)	$1.00	$1.60
Average sales price per Boe [(2)]	$13.00	$2.20	$4.74	$5.58
Selected operating expenses (in thousands):				
Production taxes	$2	$326	$315	$1,147
Lease operating expenses	$121	$884	$822	$3,454
Transportation, treating and gathering	$1	$612	$618	$1,645
Selected operating expenses per Boe[(3)]:				
Production taxes	—	$0.45	$0.47	$0.56
Lease operating expenses	—	$1.21	$1.23	$1.70
Transportation, treating and gathering	—	$0.84	$0.92	$0.81
Production costs[(4)]	—	$1.59	$2.10	$1.98

(1) The three and nine months ended September 30, 2016 reflects the impact of the Appalachian Basin Sale completed on April 8, 2016.
(2) Excludes the impact of hedging activities.
(3) Selected operating expenses per Boe for the three months ended September 30, 2016 are not meaningful due to immaterial production volumes and expense amounts. Thus, selected operating expenses per Boe for the three months ended September 30, 2016 are not presented.
(4) Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Results of Operations

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016(1)	2015	2016(1)	2015
	(In thousands, except per unit amounts)			
Net Production:				
Oil and condensate (MBbl)	242	330	837	1,066
Natural gas (MMcf)	1,009	3,490	5,232	10,360
NGLs (MBbl)	128	338	616	854
Total net production (MBoe)	539	1,249	2,325	3,646
Net Daily production:				
Oil and condensate (MBbl/d)	2.6	3.6	3.1	3.9
Natural gas (MMcf/d)	11.0	37.9	19.1	37.9
NGLs (MBbl/d)	1.4	3.7	2.2	3.1
Total net daily production (MBoe/d)	5.9	13.6	8.5	13.4
Average sales price per unit:				
Oil and condensate per Bbl, excluding impact of hedging activities	$42.55	$38.89	$36.41	$42.94
Oil and condensate per Bbl, including impact of hedging activities(2)	$47.19	$44.84	$43.85	$48.30
Natural gas per Mcf, excluding impact of hedging activities	$2.48	$0.99	$1.60	$1.36
Natural gas per Mcf, including impact of hedging activities(2)	$2.76	$1.57	$1.86	$1.93
NGLs per Bbl, excluding impact of hedging activities	$13.22	$2.35	$8.28	$5.94
NGLs per Bbl, including impact of hedging activities(2)	$15.01	$10.64	$10.55	$14.32
Average sales price per Boe, excluding impact of hedging activities	$26.92	$13.68	$18.91	$17.81
Average sales price per Boe, including impact of hedging activities(2)	$29.96	$19.11	$22.77	$22.95
Selected operating expenses:				
Production taxes	$400	$655	$1,469	$2,317

Lease operating expenses	$5,166	$5,214	$15,829	$18,475
Transportation, treating and gathering	$338	$615	$1,346	$1,654
Depreciation, depletion and amortization	$5,223	$15,394	$24,543	$45,945
Impairment of natural gas and oil properties	$—	$181,966	$48,497	$282,118
General and administrative expense	$3,925	$4,683	$15,872	$13,352
Selected operating expenses per Boe:				
Production taxes	$0.74	$0.52	$0.63	$0.64
Lease operating expenses(3)	$9.59	$4.17	$6.81	$5.07
Transportation, treating and gathering	$0.63	$0.49	$0.58	$0.45
Depreciation, depletion and amortization	$9.70	$12.32	$10.56	$12.60
General and administrative expense	$7.29	$3.75	$6.83	$3.66
Production costs(4)	$10.11	$4.40	$7.37	$5.22

(1) The three and nine months ended September 30, 2016 reflect the impact of the Appalachian Basin Sale completed on April 8, 2016.
(2) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.
(3) Lease operating expenses for the three and nine months ended September 30, 2016 include $592,000 and $1.4 million of workover expense for production enhancing WEHLU well workovers. Lease operating expenses for the three and nine months ended September 30, 2015 include $1.1 million and $3.8 million, respectively, of workover expense for production enhancing WEHLU workovers. Excluding workover, lease operating expense per Boe for the three and nine months ended September 30, 2016 would have been $8.49 per Boe and $6.19 per Boe, respectively, compared to $3.30 per Boe and $4.01 per Boe for the three and nine months ended September 30, 2015, respectively.
(4) Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Three Months Ended September 30, 2016 compared to the Three Months Ended September 30, 2015

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) as reported were $14.5 million for the three months ended September 30, 2016, down 15% from $17.1 million for the three months ended September 30, 2015. The decrease in revenues was the result of a 57% decrease in production offset by a 97% increase in weighted average realized equivalent prices. The decrease in production was the result of the Appalachian Basin Sale on April 8, 2016. Average daily production on an equivalent basis was 5.9 MBoe/d for the three months ended September 30, 2016 compared to 13.6 MBoe/d for the same period in 2015, of which Appalachian Basin production was 7.9 MBoe/d. Oil, condensate and NGLs production represented approximately 69% of total production for the three months ended September 30, 2016 compared to 53% of total production for the three months ended September 30, 2015. Excluding the impact of the Appalachian Basin production sales on oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging), total oil, condensate, natural gas and NGLs revenues decreased $1.0 million, or 7%, to $14.5 million for the three months ended September 30, 2016 from the three months ended September 30, 2015 as a result of a 9% decrease in weighted average realized equivalent prices in the Mid-Continent offset by a 3% increase in average daily equivalent production in the Mid-Continent.

Oil and condensate revenues represented approximately 71% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2016 compared to 75% for the three months ended September 30, 2015 as reported and 79% for the three months ended September 30, 2015 excluding the impact of Appalachian Basin production. Total liquids revenues (oil, condensate and NGLs) represented approximately 83% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2016 and 80% of our total oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2015 as reported and 86% excluding the impact of Appalachian Basin production.

During the three months ended September 30, 2016, we had commodity derivative contracts covering approximately 61% of our oil and condensate production. The impact of hedging on oil and condensate sales during the three months ended September 30, 2016 was an increase of $1.1 million in oil and condensate revenues and resulted in an increase in total price realized from $42.55 per Bbl to $47.19 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period was reduced by $291,000 for deferred put premiums and $192,000 for amortization of prepaid premiums. During the three months ended September 30, 2015, the impact of hedging on oil and condensate sales was an increase of $2.0 million, which resulted in an increase in total price realized from $38.89 per Bbl to $44.84 per Bbl. We designated 15% and 50% of our crude hedges as price protection for our NGLs production for the quarters ended September 30, 2016 and 2015, respectively.

During the three months ended September 30, 2016, we had commodity derivative contracts covering approximately 57% of our natural gas production. The impact of hedging on natural gas sales during the three months ended September 30, 2016 was an increase of $283,000 in natural gas revenues and resulted in an increase in total price realized from $2.48 per Mcf to $2.76 per Mcf. The gain on natural gas commodity derivatives contracts settled during the period was reduced by $26,000 for deferred put premiums. During the three months ended September 30, 2015, the impact of hedging on natural gas sales was an increase of $2.0 million in natural gas revenues resulting in an increase in total price realized from $0.99 per Mcf to $1.57 per Mcf.

During the three months ended September 30, 2016, we had commodity derivative contracts covering approximately 56% of our NGLs production. The impact of hedging on NGLs sales during the three months ended September 30, 2016 was an increase of $230,000 in NGLs revenues and resulted in an increase in total price realized from $13.22 per Bbl to $15.01 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period was reduced by $51,000 for deferred put premiums and $34,000 for amortization of prepaid premiums. During the three months ended September 30, 2015, the impact of hedging on NGLs sales was an increase of $2.8 million in NGLs revenues which resulted in an increase in total price realized from $2.35 per Bbl to $10.64 per Bbl.

The change in mark to market value for outstanding commodity derivatives contracts for the three months ended September 30, 2016 was a loss of $3.1 million compared to a gain of $4.5 million for the three months ended September 30, 2015. The change in the mark to market value is primarily the result of changes in hedge contracts and the future price curve compared to the prior year.

For additional information regarding our oil and condensate hedging positions as of September 30, 2016, see Part I, Item 1. “Financial Statements, Note 6 – Derivative Instruments and Hedging Activity” of this report.

Production taxes. We reported production taxes of $400,000 for the three months ended September 30, 2016 compared to $655,000 for the three months ended September 30, 2015. The decrease in production taxes primarily resulted from the completion of our Appalachian Basin Sale. Excluding the Appalachian Basin, production taxes increased $69,000, or 21%, to $398,000 for the three months ended September 30, 2016 from the three months ended September 30, 2015 primarily due to adjustments for WEHLU severance tax reimbursements. As reported, production taxes for the three months ended September 30, 2016 and 2015 were approximately 2.8% and 3.8%, respectively, of oil, condensate, natural gas and NGLs revenues. Excluding the Appalachian Basin, production taxes were approximately 2.7% and 2.1% of oil, condensate, natural gas and NGLs revenues for the three months ended September 30, 2016 and 2015, respectively.

Lease operating expenses. We reported lease operating expenses (“LOE”) of $5.2 million for the three months ended September 30, 2016 and 2015. Our total LOE, as reported, was $9.59 per Boe for the three months ended September 30, 2016 compared to $4.17 per Boe for the same period in 2015. Excluding the Appalachian Basin, LOE increased $716,000, or 17%, to $5.0 million for the three months ended September 30, 2016 from the three months ended September 30, 2015 due primarily to a $1.2 million increase in controllable LOE partially associated with higher water disposal costs related to flush production of new wells offset by a $499,000 decrease in workover expense. Excluding the Appalachian Basin and workover expense, LOE per Boe for the three months ended September 30, 2016 was $8.30 compared to $6.23 for the three months ended September 30, 2015.

Transportation, treating and gathering. We reported transportation expenses of $338,000 for the three months ended September 30, 2016 compared to $615,000 for the three months ended September 30, 2015. Excluding the impact of the Appalachian Basin Sale, transportation expense in the Mid-Continent increased $334,000 for the three months ended September 30, 2016 compared to the three months ended September 30, 2015 due to new wells and changes in Oklahoma marketing contracts from percent of proceeds to more fixed charges basis.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization (“DD&A”) expense of $5.2 million for the three months ended September 30, 2016 down from $15.4 million for the three months ended September 30, 2015. The decrease in DD&A expense was the result of a 57% decrease in production resulting from the completion of the Appalachian Basin Sale coupled with a lower DD&A rate due to impairment charges incurred in 2015 and first quarter 2016 and the credit to the full cost pool for the net proceeds from the Appalachian Basin Sale. The DD&A rate for the three months ended September 30, 2016 was $9.70 per Boe compared to $12.32 per Boe for the same period in 2015.

General and administrative expense. We reported general and administrative expenses of $3.9 million for the three months ended September 30, 2016 compared to $4.7 million for the three months ended September 30, 2015. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $810,000 and $1.2 million for the three months ended September 30, 2016 and 2015, respectively. Excluding stock-based compensation expense, general and administrative expense decreased $414,000 to $3.1 million for the three months ended September 30, 2016 compared to the three months ended September 30, 2015. This decrease is primarily due to lower acquisition costs related to the Husky Acquisition.

Litigation settlement benefit. We reported a litigation settlement benefit of $10.1 million for the three months ended September 30, 2016. The litigation settlement benefit is for recovery in connection with a legal settlement with our insurers regarding a claim previously denied under our directors and officers liability insurance coverage to recover settlement and legal defense expenses incurred by us in connection with litigation settled in December 2010. Legal costs incurred associated to this settlement for the three months ended September 30, 2016 and 2015 were $186,000 and $183,000, respectively.

Interest expense. We reported interest expense of $8.2 million for the three months ended September 30, 2016 compared to $7.9 million for the three months ended September 30, 2015. The increase in interest expense is primarily due to additional borrowings and higher grid pricing under revolving credit facility pursuant to the Second Amended and Restated Credit Agreement among the Company, Wells Fargo Bank, National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and Issuing Lender and the lenders named therein (the "Revolving Credit Facility").

Dividends on preferred stock. We reported accrued dividends on preferred stock of $3.6 million for the three months ended September 30, 2016 and 2015, respectively. Dividends accrued for the three months ended September 30, 2016 were accumulated and remain unpaid. The Company's 8.625% Series A Cumulative Preferred Stock (the "Series A Preferred Stock") had a stated value and liquidation preference (excluding accrued and unpaid dividends) of approximately $101.1 million at September 30, 2016 and 2015, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends accrued on the Series A Preferred Stock were $2.2 million for the three months ended September 30, 2016 and 2015, respectively. The Company's 10.75% Series B Cumulative Preferred Stock (the "Series B Preferred Stock") had a stated value and liquidation preference (excluding accrued and unpaid dividends) of $53.5 million at September 30, 2016 and 2015 and carries a cumulative dividend rate of 10.75% per annum. Dividends accrued on the Series B Preferred Stock were $1.4 million for the three months ended September 30, 2016 and 2015, respectively. Effective March 9, 2016 and commencing April 2016, our Revolving Credit Facility prohibits the payment of cash dividends on our preferred stock. Dividends on the Series A Preferred Stock and Series B Preferred Stock have and will continue to accumulate regardless of whether any such dividends are declared or not.

Nine Months Ended September 30, 2016 compared to the Nine Months Ended September 30, 2015

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) as reported were $44.0 million for the nine months ended September 30, 2016, down 32% from $65.0 million for the nine months ended September 30, 2015. The decrease in revenues was the result of a 36% decrease in production offset by a 6% increase in weighted average realized prices. The decrease in production was the result of the Appalachian Basin Sale on April 8, 2016. Average daily production on an equivalent basis was 8.5 MBoe/d for the nine months ended September 30, 2016 compared to 13.4 MBoe/d for the same period in 2015, of which Appalachian Basin production was 7.4 MBoe/d. Oil, condensate and NGLs production represented approximately 62% of total production for the nine months ended September 30, 2016 compared to 53% of total production for the nine months ended September 30, 2015. Excluding the impact of Appalachian Basin production sales on oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging), total oil, condensate, natural gas and NGLs revenues decreased $12.8 million, or 24%, to $40.8 million for the nine months ended September 30, 2016 from the nine months ended September 30, 2015 as a result of a 26% decrease in weighted average realized equivalent prices slightly offset by a 3% increase in production in the Mid-Continent.

Oil and condensate revenues as reported represented approximately 69% of our total oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2016 compared to 70% for the nine months ended September 30, 2015. Total liquids revenues (oil, condensate and NGLs) as reported represented approximately 81% of our total oil, condensate, natural gas and NGLs revenues for the nine month period ended September 30, 2016 compared to 78% for the nine month period ended September 30, 2015. Excluding the impact of Appalachian Basin production sales, oil and condensate revenues represented approximately 73% of our total Mid-Continent oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2016 compared to 79% for the nine months ended September 30, 2015. Excluding the impact of Appalachian Basin production sales, total liquids revenues (oil, condensate and NGLs) represented approximately 85% of our total Mid-Continent oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2016 compared to 87% for the nine months ended September 30, 2015.

During the nine months ended September 30, 2016, we had commodity derivative contracts covering approximately 50% of our oil and condensate production. The impact of hedging on oil and condensate sales during the nine months ended September 30, 2016 was an increase of $6.2 million in oil and condensate revenues and resulted in an increase in total price realized from $36.41 per Bbl to $43.85 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the period includes a loss of $2.0 million for deferred put premiums and $192,000 for the amortization of prepaid premiums. During the nine months ended September 30, 2015, the impact of hedging on oil and condensate sales was an increase of $5.7 million in oil and condensate revenues, which resulted in an increase in total price realized from $42.94 per Bbl to $48.30 per Bbl. We designated 15% and 50% of our current crude hedges as price protection for our NGLs production for the nine months ended September 30, 2016 and 2015, respectively.

During the nine months ended September 30, 2016, we had commodity derivative contracts covering approximately 47% of our natural gas production. The impact of hedging on natural gas sales during the nine months ended September 30, 2016 was an increase of $1.4 million in natural gas revenues and resulted in an increase in total price realized from $1.60 per Mcf to $1.86 per Mcf. The gain on natural gas commodity derivative contracts settled during the period includes a gain of $75,000 for amortization of prepaid premiums. Excluding the non-cash amortization, the impact of hedging on natural gas sales was an increase in revenues of $3.2 million of NYMEX hedge gains offset by $1.7 million of basis hedge losses and $261,000 of deferred put premiums. During the nine months ended September 30, 2015, the impact of hedging on natural gas sales was an increase of $5.9 million in natural gas revenues resulting in an increase in total price realized from $1.36 per Mcf to $1.93 per Mcf.

During the nine months ended September 30, 2016, we had commodity derivative contracts covering approximately 35% of our NGLs production. The impact of hedging on NGLs sales during the nine months ended September 30, 2016 was an increase of $1.4 million in NGLs revenues and resulted in an increase in total price realized from $8.28 per Bbl to $10.55 per Bbl. The gain on NGLs commodity derivatives contracts settled during the period includes a loss of $357,000 for deferred put premiums and $34,000 for the amortization of prepaid premiums. During the nine months ended September 30, 2015, the impact of hedging on NGLs sales was an increase of $7.2 million in NGLs revenues which resulted in an increase in total price realized from $5.94 per Bbl to $14.32 per Bbl.

The change in mark to market value for outstanding commodity derivative contracts for nine months ended September 30, 2016 was a loss of $13.0 million compared to a gain of $986,000 for the nine months ended September 30, 2015. The change in the mark to market value was primarily the result of changes in hedge contracts and the futures price curve compared to the prior year.

For additional information regarding our oil and condensate hedging positions as of September 30, 2016, see Part I, Item 1. "Financial Statements, Note 6 – Derivative Instruments and Hedging Activity" of this report.

Production taxes. We reported production taxes of $1.5 million for the nine months ended September 30, 2016 compared to $2.3 million for the nine months ended September 30, 2015. The decrease in production taxes primarily resulted from the completion of our Appalachian Basin Sale on April 8, 2016. Excluding the Appalachian Basin, production taxes in the Mid-Continent decreased $15,000, or 1%, to $1.2 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. As reported, production taxes for the nine months ended September 30, 2016 and 2015 were approximately 3.3% and 3.6%, respectively, of oil, condensate, natural gas and NGLs revenues. Excluding the Appalachian Basin, production taxes were approximately 2.8% and 2.2% of oil, condensate, natural gas and NGLs revenues for the nine months ended September 30, 2016 and 2015, respectively.

Lease operating expenses. We reported LOE of $15.8 million for the nine months ended September 30, 2016 compared to $18.5 million for the nine months ended September 30, 2015. Our total LOE, as reported, was $6.81 per Boe for the nine months ended September 30, 2016 compared to $5.07 per Boe for the same period in 2015. Excluding the Appalachian Basin, LOE decreased $14,000 to $15.0 million for the nine months ended September 30, 2016 from the nine months ended September 30, 2015. Excluding the Appalachian Basin and workover expense, LOE per Boe for the nine months ended September 30, 2016 was $8.20 compared to $6.94 for the nine months ended September 30, 2015. The increase in LOE per Boe in 2016 was partially associated with higher water disposal costs related to flush production of new wells.

Transportation, treating and gathering. We reported transportation expenses of $1.3 million for the nine months ended September 30, 2016 compared to $1.7 million for the nine months ended September 30, 2015. Excluding the Appalachian Basin, transportation expense in the Mid-Continent increased $720,000 for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 due to new wells and changes in Oklahoma marketing contracts from percent of proceeds to more fixed charges basis.

Depreciation, depletion and amortization. We reported DD&A expense of $24.5 million for the nine months ended September 30, 2016 down from $45.9 million for the nine months ended September 30, 2015. The decrease in DD&A expense was the result of a 36% decrease in production resulting from the completion of the Appalachian Basin Sale on April 8, 2016 coupled with a 16% decrease in the DD&A rate per Boe. The DD&A rate for the nine months ended September 30, 2016 was $10.56 per Boe compared to $12.60 per Boe for the same period in 2015. The decrease in the rate is primarily due to impairment charges incurred in 2015 and first quarter 2016 and the credit to the full cost pool for the net proceeds from the Appalachian Basin Sale.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $48.5 million for the nine months ended September 30, 2016, which was recorded at March 31, 2016. The impairment was the result of a 38% decline in the 12-month average natural gas price and a 44% decline in the 12-month average oil price used in the calculation of the full cost ceiling test at March 31, 2016 compared to March 31, 2015. At March 31, 2016, our ceiling test impairment calculation was based on SEC pricing of $2.40 per MMBtu of Henry Hub spot natural gas and $46.26 per barrel of WTI spot oil. For a description of the ceiling impairment determination and the impact of recent price declines on such impairments, see Part I, Item 1. “Financial Statements, Note 3 – Property, Plant and Equipment.”

General and administrative expense. We reported general and administrative expenses of $15.9 million for the nine months ended September 30, 2016 compared to $13.4 million for the nine months ended September 30, 2015. Non-cash stock-based compensation expense, which is included in general and administrative expense, decreased $782,000 to $3.1 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. Excluding stock-based compensation expense, general and administrative expense increased $3.3 million to $12.7 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015. This increase is primarily due to allowance for bad debt expense costs of $2.0 million related to the bankruptcy of a third-party purchaser of our production primarily in West Virginia, $677,000 of severance costs for the Appalachian Basin staff and the retirement of the chief operating officer, and $412,000 of additional legal costs.

Litigation settlement benefit. We reported a litigation settlement benefit of $10.1 million for the nine months ended September 30, 2016. The litigation settlement benefit is for recovery in connection with a legal settlement with our insurers regarding a claim previously denied under our directors' and officers' liability insurance coverage to recover settlement and legal defense expenses incurred by us in connection with litigation settled in December 2010. Legal costs incurred associated to this settlement for the nine months ended September 30, 2016 and 2015 were $455,000 and $205,000, respectively.

Interest expense. We reported interest expense of $26.7 million for the nine months ended September 30, 2016 compared to $22.4 million for the nine months ended September 30, 2015. The increase in interest expense is primarily due to additional borrowings and higher grid pricing under the Revolving Credit Facility and lower capitalized interest as a result of the Appalachian Basin Sale.

Dividends on preferred stock. We reported accrued dividends on preferred stock of $10.9 million for the nine months ended September 30, 2016 and 2015, respectively. Dividends accrued for the period April through September 2016 were accumulated and remained unpaid. The Series A Preferred Stock had a stated value and liquidation preference (excluding accrued and unpaid dividends) of approximately $101.1 million at September 30, 2016 and 2015, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends accrued on the Series A Preferred Stock were $6.6 million for the nine months ended September 30, 2016 and 2015, respectively. The Series B Preferred Stock had a stated value and liquidation preference (excluding accrued and unpaid dividends) of $53.5 million at September 30, 2016 and 2015, respectively, and carries a cumulative dividend rate of 10.75% per annum. Dividends accrued on the Series B Preferred Stock were $4.3 million for the nine months ended September 30, 2016 and 2015. Effective March 9, 2016 and commencing April 2016, our Revolving Credit Facility prohibits the payment of cash dividends on our preferred stock. Dividends on the Series A Preferred Stock and Series B Preferred Stock have and will continue to accumulate regardless of whether such dividends are declared or not.

Liquidity and Capital Resources

Overview. Our primary sources of liquidity and capital resources are internally generated cash flows from operating activities, possible asset sales and capital markets transactions, to the extent available on favorable terms. We believe that our current cash position, funds from operating cash flows and proceeds from divestitures and capital markets transactions should be sufficient to meet our cash requirements for the remainder of 2016 and 2017, subject to our ability to extend maturities or refinancing of our long term debt as described below by the last quarter of 2017. We continually evaluate our capital needs and compare them to our capital resources and ability to raise funds in the financial markets. We have the ability to adjust capital expenditures in response to changes in oil, condensate, natural gas and NGLs prices, drilling results, liquidity and cash flow. On May 12, 2016, we sold 50,000,000 shares of our common stock in an underwritten public offering at a price of $0.95 per share, or $47.5 million before offering costs and expenses. We received approximately $44.8 million of proceeds from the offering, net of offering costs and expenses of approximately $2.7 million.

In light of our approaching maturities of our Revolving Credit Facility in November 2017 and our Notes (as defined below) in May 2018, we are continuing to analyze and engage in discussions regarding various alternatives to either extend our debt maturities, reduce the level of our long-term debt or otherwise reduce our future debt service obligations. These alternatives could involve the application of proceeds from possible further targeted assets sales or sales of equity securities, debt repurchases, exchanges of existing debt securities for new debt securities, exchanges or conversions of existing debt securities for new equity securities, or a combination of the foregoing. Currently, however, we have no definitive plans, understandings or agreements in place to undertake any such transactions.

On October 14, 2016, we executed the Development Agreement with the Investor to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma. The Drilling Program will target the Meramec and Osage formations within the Mississippi Lime on a contract area within three townships covering approximately 18,000 undeveloped net mineral acres under leases held by us. We will be the operator of all wells jointly developed under the Development Agreement. Under the Development Agreement, the Investor will fund 90% of our working interest portion of drilling and completion costs to initially earn 80% of our working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, we will pay 10% of our working interest portion of such costs for 20% of our original working interest in the well.

On October 19, 2016, we entered into a purchase and sale agreement to sell certain non-core leasehold interests in approximately 25,300 net acres of which only 19,100 net acres was ascribed allocated value and interests in 25 gross (11.2 net) wells primarily in northeast Canadian County and also in southeast Kingfisher County, Oklahoma to Red Bluff for approximately $71.0 million (of which up to $10.0 million is contingent upon the satisfaction of certain conditions), subject to certain adjustments. Current production for the wells included in the sale is approximately 164 barrels of oil equivalent per day. The transaction is expected to close on or before November 18, 2016, with a property sale effective date of August 1, 2016. Pursuant to the Revolving Credit Facility, 20% of the future net sales proceeds from the sale of the Company's South STACK Play acreage will be used to pay down the outstanding Revolving Credit Facility balance. Current market conditions may put limitations on our ability to issue new debt or equity securities in the public or private markets. The ability of oil and natural gas companies to access the equity and high yield debt markets has been significantly limited since the decline in commodity prices.

For the nine months ended September 30, 2016, we reported cash flows provided by operating activities of $21.8 million. For the nine months ended September 30, 2016, we reported net cash provided by investing activities of $35.7 million primarily from proceeds from the Appalachian Basin Sale of $77.5 million offset by $43.2 million for the development of oil and natural gas properties. For the nine months ended September 30, 2016, we reported net cash used in financing activities of $60.8 million, consisting primarily of $100.4 million of repayment of borrowings under our Revolving Credit Facility partially offset by $44.8 million of proceeds from the issuance of common equity and $3.6 million of preferred stock dividends paid. As a result of these activities, our cash and cash equivalents balance decreased by $3.3 million, resulting in a cash and cash equivalents balance of $46.7 million at September 30, 2016.

At September 30, 2016, we had a net working capital surplus of approximately $29.8 million. At September 30, 2016, we had $99.6 million of borrowings outstanding and $370,000 of letters of credit issued under our Revolving Credit Facility with no availability.

Our substantial borrowings relative to our current cash flows and proved reserve base limits our operational flexibility, including our ability to make capital expenditures to fully exploit and enhance the value of our undeveloped oil and natural gas properties. We are highly leveraged and may not be able to generate sufficient cash or cash flows, as applicable, to service all of our indebtedness or to meet financial covenants under our debt agreements and may be forced to take other actions to satisfy our obligations under such agreements, which may not be successful, or if successful, could adversely affect our creditors and be highly dilutive to our existing holders of our common and preferred stock or possibly cause the loss of substantially all of their investment. For a description of possible actions we may consider to improve our liquidity, see "Part II. Other Information, Item 1A. Risk Factors – We are highly leveraged and may not be able to generate sufficient cash or cash flows, as applicable, to service all of our indebtedness or to meet financial covenants under our debt agreements and may be forced to take other actions to satisfy our obligations under such agreements, which may not be successful, or if successful, could be highly dilutive to, and adversely affect, creditors and our existing holders of our common and preferred stock."

Future capital and other expenditure requirements. Capital expenditures in the Mid-Continent for the remainder of 2016 are currently projected to be approximately $13.4 million comprised of $2.0 million for drilling, completion and infrastructure costs, $9.9 million for lease renewal and extension costs and $1.5 million for capitalized general and administrative costs. The majority of the drilling and completion costs represents the Company's share of the Drilling Program costs and are required expenditures. Failure to fund lease acquisition expenditures will result in the forfeiture of leasehold rights on some of our properties. During the remainder of 2016, we have approximately 6,900 net acres expiring in the Mid-Continent, including approximately 150 net acres that have automatic extension rights, and have allocated funds for such renewals. We plan to fund our remaining 2016 capital budget through existing cash balances, internally generated cash flow from operating activities and possible capital markets transactions and divestitures of assets, or some combination thereof.

We continue to monitor the volatility in the commodity markets and we are developing capital plans responsive to changes that are occurring in the commodity and capital markets. Our capital expenditures and the scope of our drilling activities may change as a result of several factors, including, but not limited to, changes in oil, condensate, natural gas and NGLs prices, costs of drilling and completion and leasehold acquisitions, drilling results, and changes in the borrowing base under the Revolving Credit Facility. Based on current projected available capital resources, including divestiture proceeds, and assuming no additional debt service requirements, we should have ample liquidity to fund our current operating plan.

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. For 2016, we have designated 15% 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, 2016, the estimated fair value of all of our commodity derivative instruments was a net asset of $9.1 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 October 2016 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 October 2016 through December 2018. At September 30, 2016, we had a current commodity premium payable of $1.8 million and a long-term commodity premium payable of $1.4 million. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

As of September 30, 2016, all of our commodity derivative hedge positions were with 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.

ATM Program. We have an at-the-market equity offering program (the “ATM Program”) pursuant to which we may issue and sell shares of our common stock having an aggregate offering price up to $50.0 million in amounts and at times as we determine from time to time. Actual issuances, if any, will depend on a variety of factors to be determined by us, including, among others, market conditions, the trading price of our common stock, our determinations of the appropriate sources of funding for our company and potential uses of funding available to us. To date, no shares of common stock have been issued under the ATM Program.

Revolving Credit Facility. Our Revolving Credit Facility provides for a maximum amount of $500.0 million, subject to a borrowing base, which, at September 30, 2016 and November 1, 2016, was $100.0 million. At September 30, 2016, we had $99.6 million of borrowings outstanding and $370,000 of letters of credit issued under our Revolving Credit Facility. As of November 1, 2016, there were $99.6 million of borrowings outstanding and $370,000 of letters of credit issued under our Revolving Credit Facility. At September 30, 2016, we were in compliance with all financial covenants under the Revolving Credit Facility.

Effective October 14, 2016, we entered into an amendment to our Revolving Credit Facility which (i) reaffirmed our borrowing base at $100.0 million (the current amount outstanding under the facility as noted above) with the next redetermination scheduled for November 2016; (ii) requires us to reduce our outstanding Revolving Credit Facility balance by 20% of any future net sales proceeds from the sale of our STACK Play acreage primarily located in Canadian County, Oklahoma; (iii) modified our minimum interest coverage ratio to 0.8 to 1.0 for the fourth quarter 2016 and first quarter 2017, 1.0 to 1.0 for the second quarter 2017 and 2.50 to 1.0 thereafter, each as determined using adjusted EBITDA for the previous four quarters; and (iv) modified provisions related to lien and asset dispositions to accommodate the Drilling Program. 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. We have $325.0 million of 8.625% senior secured notes outstanding, which are due May 15, 2018 (the “Notes”). 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, 2016, we were in compliance with all covenants under the indenture governing the Notes. Covenants in the indenture governing our senior secured notes also limit our ability to borrow on a first priority lien secured basis, including our ability to refinance the full amount of currently outstanding borrowings under our Revolving Credit Facility or to reborrow on such facility in the event current borrowings thereunder are paid down.

Series A Preferred Stock. Prior to April 2016, we paid cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the aggregate $101.1 million stated value and liquidation preference. Dividends accrued for the period April through September 2016 were accumulated and remained unpaid. For the three and nine months ended September 30, 2016, we recognized dividends of $2.2 million and $6.6 million, respectively, for the Series A Preferred Stock. Effective March 9, 2016, our Revolving Credit Facility prohibited the payment of cash dividends on our preferred stock commencing April 2016. Accordingly, we ceased payment of dividends on our Series A Preferred Stock in April 2016. Dividends accrued on the Series A Preferred Stock have and will continue to accumulate regardless of whether any such dividends are declared or not.

If we fail to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then commencing in the calendar month following the first month in such fourth calendar quarter in which cash dividends are not paid in full, and until accumulated dividends are paid in full for four calendar quarters with the last two calendar quarters' dividends paid in cash, (i) the fixed rate of Series A Preferred Stock increases by 2.00%, (ii) the Company may be required to issue a dividend of common stock to pay accrued and unpaid dividends, if such dividends are not paid in cash, provided it has sufficient surplus to pay such a dividend under state law and (iii) the holders of Series A Preferred Stock and Series B Preferred Stock, voting as a single class, will have the right to elect up to two additional directors to the board of directors of the Company.

Series B Preferred Stock. Prior to April 2016, we paid cumulative dividends on the Series B Preferred Stock at a fixed rate of 10.75% per annum of the aggregate $53.5 million stated value and liquidation preference. Dividends accrued for the period April through September 2016 were accumulated and remained unpaid. For the three and nine months ended September 30, 2016, we recognized dividends of $1.4 million and $4.3 million, respectively, for the Series B Preferred Stock. Effective March 9, 2016, our Revolving Credit Facility prohibited the payment of cash dividends on our preferred stock commencing April 2016. Accordingly, we ceased payment of dividends on our Series B Preferred Stock in April 2016. Dividends accrued on the Series B Preferred Stock have and will continue to accumulate regardless of whether any such dividends are declared or not.

If we fail to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then commencing in the calendar month following the first month in such fourth calendar quarter in which cash dividends are not paid in full, and until accumulated dividends are paid in full for four calendar quarters with the last two calendar quarters' dividends paid in cash, (i) the fixed rate of Series B Preferred Stock increases by 2.00%, (ii) the Company may be required to issue a dividend of common stock to pay accrued and unpaid dividends, if such dividends are not paid in cash, provided it has sufficient surplus to pay such a dividend under state law and (iii) the holders of Series A Preferred Stock and Series B Preferred Stock, voting as a single class, will have the right to elect up to two additional directors to the board of directors of the Company.

We suspended the declaration and payment of all monthly dividends after March 2016 on our Series A Preferred Stock and Series B Preferred Stock. After January 31, 2017, if we do not pay all accumulated and unpaid dividends on our outstanding preferred stock in cash, we may be required to issue a significant number of shares of common stock as dividends to holders of our outstanding preferred stock, which will dilute our common stockholders and may adversely affect the trading price of our common stock. The number of shares of common stock paid as dividends, if paid in respect of Series A Preferred Stock or Series B Preferred Stock, would be determined based upon a ten day average last sale trading price of the common stock immediately prior (or reasonably close in time to) the dividend payment date. Under certain circumstances, in lieu of cash or common stock dividends, we may be required to make "pay in kind" dividends of Series A Preferred Stock and Series B Preferred Stock. Payments of stock dividends on our preferred stock could be substantially dilutive to stockholders. See "Part II, Other Information. Item 1A. Risk Factors. – After January 31, 2017, if we do not pay all accumulated and unpaid dividends on our outstanding preferred stock in cash, we may be required to issue a significant number of shares of common stock as dividends to holders of our outstanding preferred stock, which will dilute our common stockholders and may adversely affect the trading price of our common stock."

Off-Balance Sheet Arrangements

As of September 30, 2016, 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 11 – 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.

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 2015 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 Accounting 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, unpredictable and 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, 2016, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate $1.5 million and $4.4 million, impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk, respectively. 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

We are exposed to changes in interest rates as a result of our Revolving Credit Facility. At September 30, 2016, we had $99.6 million of borrowings outstanding under our Revolving Credit Facility. Based on the amount outstanding under our Revolving Credit Facility at September 30, 2016, a one percentage point change in the interest rate would have had a per month impact of $83,000 on our interest expense. We have not entered into interest rate hedging arrangements in the past, and have no current plans to do so. Due to the potential for fluctuating balances in the amount outstanding under our Revolving Credit Facility, we do not believe such arrangements to be cost effective. 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 our 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, 2016. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2016, 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, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 11 – Commitments and Contingencies” of this report.

Item 1A. Risk Factors

In addition to the risk factors below and the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. “Risk Factors” in our 2015 Form 10-K and Part II, Item 1A. “Risk Factors” and elsewhere in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2016 and June 30, 2016, which could materially affect our business, financial condition or future results. 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.

We are highly leveraged and may not be able to generate sufficient cash or cash flows, as applicable, to service all of our indebtedness or to meet financial covenants under our debt agreements and may be forced to take other actions to satisfy our obligations under such agreements, which may not be successful, or if successful, could be highly dilutive to, and adversely affect, creditors and our existing holders of our common and preferred stock.

Our ability to make scheduled payments on or to refinance our indebtedness obligations and to meet related financial covenants applicable to our debt instruments, including our Revolving Credit Facility and our $325.0 million outstanding principal amount of our Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control, as well as our ability to complete proposed asset sales. As of November 1, 2016, our cash balance was approximately $38.5 million. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, if any, and interest on our indebtedness, including the Notes.

Our level of indebtedness will have several important effects on our future operations, including, without limitation:

•requiring us to dedicate a significant portion of our cash flows from operations to support the payment of debt service and reduce our capital expenditures required to maintain or grow our reserves and production base;

•increasing our vulnerability to adverse changes in general economic and industry conditions, and putting us at a competitive disadvantage relative to competitors that have fewer fixed obligations and greater cash flows to devote to their businesses;

•limiting our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes; and

•limiting our flexibility in operating our business and preventing us from engaging in certain transactions that might otherwise be beneficial to us.

In light of our approaching maturities of our Revolving Credit Facility in November 2017 and our Notes in May 2018, we are continuing to analyze and engage in discussions regarding various alternatives to either extend our debt maturities, reduce the level of our long-term debt or otherwise reduce our future debt service obligations. These alternatives could involve the application of proceeds from possible further targeted assets sales or sales of equity securities, debt repurchases, exchanges of existing debt securities for new debt securities, exchanges or conversions of existing debt securities for new equity securities, or a combination of the foregoing. Currently, however, we have no definitive plans, understandings or agreements in place to undertake any such transactions.

Additionally, due to the relatively high level of our indebtedness, on April 8, 2016, we sold substantially all of our producing assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for an adjusted sales price of $75.7 million, net of $3.5 million of suspense liability transferred to buyer, and on May 12, 2016, we sold 50,000,000 shares of our common stock in an underwritten public offering for approximately $44.8 million of net proceeds. On October 19, 2016, we entered into a purchase and sale agreement to sell certain non-core leasehold interests in northeast Canadian County and also in southeast Kingfisher County, Oklahoma for approximately $71.0 million (of which up to $10.0 million is contingent upon the satisfaction of certain conditions), subject to certain adjustments.

Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. One or more of these alternatives could potentially be consummated with the consent of any one or more of our current security holders, or, if necessary, without the consent of holders through a restructuring under a voluntary bankruptcy proceeding. Such alternatives would likely adversely affect our creditors and be highly dilutive to our existing holders of our common and preferred stock or possibly cause the loss of substantially all of their investment. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our Notes, may restrict us from adopting some of these alternatives. For example, covenants in the indenture governing the Notes also limit our ability to borrow on a first priority lien secured basis, which may limit our ability to refinance the full amount of currently outstanding borrowings under our Revolving Credit Facility or to reborrow on such facility in the event current borrowings thereunder are paid down. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our Revolving Credit Facility and the indentures governing our Notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due, including required reduction in amounts owed in our Revolving Credit Facility as a result of reductions in our borrowing base. If we are unable to meet our debt obligations, we would be forced to restructure our indebtedness and equity capitalization. Depending upon asset values and other factors, any future restructuring could be highly dilutive to existing holders of our common and preferred stock, could result in equity holders losing a significant amount or all of their investment in us and may adversely affect the trading prices and values of our existing debt and equity securities.

We may in the future seek a postponement of further reductions in our borrowing base under our Revolving Credit Facility or seek relief from financial covenant compliance for future periods under our Revolving Credit Facility, which if not successful, could require immediate repayment of a portion or all amounts borrowed on our Revolving Credit Facility and could result in actions that could be highly dilutive to, and adversely affect, our creditors and our existing holders of our common and preferred stock.

After completion of our Appalachian Basin Sale on April 8, 2016 and our related repayment of $80.0 million in outstanding borrowings, our borrowing base under our Revolving Credit Facility was reduced to $100.0 million. Effective October 14, 2016, our borrowing base was reaffirmed at $100.0 million, and as of November 1, 2016, $99.6 million of borrowings remained outstanding and $370,000 of letters of credit were issued and outstanding under the Revolving Credit Facility. The next borrowing base redetermination is scheduled for November 2016 and in connection with Amendment No. 9, a new mandatory prepayment requirement was added to the Revolving Credit Facility that requires us to repay our outstanding Revolving Credit Facility borrowings by an amount equal to 20% of any future net sales proceeds from the sale of our STACK Play acreage primarily located in Canadian County, Oklahoma. Our borrowing base is otherwise determined semi-annually by our lenders in May and November of each year and is based on our proved reserves and the value attributed to those reserves. We and the lenders each have the option to initiate a redetermination of the borrowing base between scheduled semi-annual redeterminations.

The borrowing base under our Revolving Credit Facility could be further reduced as a result of lower oil or natural gas prices, declines in estimated oil and natural gas reserves or production, our issuance of new indebtedness or for other reasons. If the borrowing base under our Revolving Credit Facility is further reduced, there would be a reduction of our available credit and the potential requirement for us to repay outstanding indebtedness in excess of the redetermined borrowing base. In addition, we may not be able to access adequate funding under our Revolving Credit Facility as a result of the inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. If our borrowing base is further reduced or we cannot access adequate funding under our Revolving Credit Facility, it will reduce the availability of our cash flow for replacing reserves through implementing our drilling and development plan, making acquisitions or otherwise carrying out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

In addition, under our Revolving Credit Facility we are required to maintain compliance with certain financial covenants, including a minimum interest coverage ratio, a maximum senior leverage ratio and for quarterly periods ending on or after June 30, 2017, a maximum leverage ratio. Under the recent commodity price environment (utilizing recent NYMEX strip commodities pricing for the remainder of the year and assuming limited capital expenditures to maintain or grow our reserves and production), we believed it likely that we would not meet the minimum interest coverage ratio applicable to our Revolving Credit Facility at year-end 2016. In addition, our compliance with the maximum leverage ratio covenant as of June 30, 2017 is uncertain. In connection with Amendment No. 9 to our Revolving Credit Facility, we were granted covenant relief and the minimum interest coverage ratio was modified to 0.8 to 1.0 for the fourth quarter 2016 and first quarter 2017, 1.0 to 1.0 for the second quarter 2017 and 2.50 to 1.0 thereafter, each as determined using adjusted EBITDA for the previous four quarters.

If we fail to comply with our financial covenant ratios or lenders under our Revolving Credit Facility reduce our borrowing base beyond our ability to repay, our lenders could accelerate the maturity of our Revolving Credit Facility and exercise remedies available to them, including foreclosure on our pledged oil and gas properties. We expect that in these circumstances, we would pursue the various alternatives described in the immediately preceding risk factor to reduce our indebtedness and repay amounts owed under our Revolving Credit Facility, all of which could be highly dilutive to existing holders of our common and preferred stock, could result in equity holders losing a significant amount or all of their investment in us and may adversely affect the trading prices and values of our existing debt and equity securities.

After January 31, 2017, if we do not pay all accumulated and unpaid dividends on our outstanding preferred stock in cash, we may be required to issue a significant number of shares of common stock as dividends to holders of our outstanding preferred stock, which will dilute our common stockholders and may adversely affect the trading price of our common stock.

We have two series of perpetual preferred stock outstanding with an aggregate stated value liquidation preference of $154.6 million (excluding accrued but unpaid dividends). Under recent amendments to our revolving credit facility, we are prohibited from paying cash dividends on our preferred stock. Accordingly, we ceased paying monthly dividends on our preferred stock effective April 2016. If we do not or cannot pay accumulated dividends on our outstanding preferred stock in cash on or before January 31, 2017, we may be required to issue shares of common stock to pay the accumulated and unpaid dividends in February 2017, which would aggregate approximately $12.1 million at February 1, 2017 (assuming no issuance of cash dividends before such date), and pay all future monthly dividends in common stock, in each case assuming our common stock is then listed on a national securities exchange or market and we have surplus under Delaware law at that time equal to or in excess of the par value of the common stock issued as dividends. The number of shares of common stock issued in lieu of cash dividends would be determined based upon weighted ten day average last sale trading price of the common stock immediately prior (or reasonably close) to the date of such dividends. If such average last sale trading price in February 2017 were equal to our last sale price at October 31, 2016 of $1.08 per share and assuming we have not issued any preferred cash dividends prior to such date, we would be obligated to issue approximately 11.2 million shares of our common stock in February 2017 (excluding shares for the February 2017 monthly dividend as described in the following sentence) to holders of our outstanding preferred stock as dividends in lieu of cash dividends. In addition, after January 31, 2017, unless and until all accrued and unpaid preferred dividends are paid in full and paid in cash for the most recent two calendar quarters, the fixed rate of dividends on each of our two outstanding series of preferred stock will increase by 2.00% per annum and monthly dividends, if not paid in cash, will be required to be paid monthly in common stock, subject to the legal requirements described above. In such event, the monthly dividend requirement for our currently outstanding preferred stock would increase to approximately $1.5 million, an increase of $258,000 per month. If the average last sales price in February 2017 were equal to our last sales price at October 31, 2016 of $1.08 per share and assuming we have not issued preferred cash dividends prior to such date, we would be obligated to issue approximately 1.4 million shares of our common stock monthly commencing February 2017. As a result, a significant number of shares of common stock may be issued as dividends on our outstanding preferred stock after January 31, 2017, which issuances will dilute the ownership of our common stockholders and may adversely affect the trading price of our common stock.

If commodity prices fall below certain thresholds, we may not be able to recognize the benefits contemplated from the Development Agreement.

The Development Agreement provides that the Investor’s payment obligations on wells not in progress can be suspended upon the occurrence of certain events based on changes in commodity prices, including the NYMEX price per barrel of crude oil averaging less than $40.00 over 30 consecutive trading days. If the NYMEX price per barrel of crude oil averages less than $35.00 over 15 consecutive trading days, the Investor has the right to suspend its payment obligations on any wells currently in progress. If commodity prices fall below these thresholds, we may not be able to recognize the benefits contemplated under the Development Agreement.

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

Issuer Purchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented. Our share repurchase activity represents shares of common stock forfeited in connection with the payment of estimated withholding taxes on shares of restricted common stock that vested during the period.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans	(d) Maximum Number of Shares that May Yet be Purchased Under the Plan
August 1, 2016 – August 31, 2016	3,664	$0.93	—	n/a

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.

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 3, 2016	By: /s/ J. RUSSELL PORTER J. Russell Porter President and Chief Executive Officer (Duly authorized officer and principal executive officer)
Date:	November 3, 2016	By: /s/ MICHAEL A. GERLICH Michael A. Gerlich Senior Vice President and Chief Financial Officer (Duly authorized officer and principal financial and accounting officer)

EXHIBIT INDEX

Exhibit Number	Description
2.1	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).
2.2	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).
2.3**	Purchase and Sale Agreement, dated October 14, 2015, by and between Gastar Exploration Inc. and Husky Ventures, Inc., Silverstar of Nevada, Inc., Maximus Exploration, LLC and Atwood Acquisitions, LLC (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on October 16, 2015. File No. 001-35211).
2.4	Letter Agreement, dated December 3, 2015, by and between Gastar Exploration Inc. and Husky Ventures, Inc., Silverstar of Nevada, Inc., Maximus Exploration, LLC and Atwood Acquisitions, LLC (incorporated by reference to Exhibit 2.18 of the Yearly Report on Form 10-K filed with the SEC on March 10, 2016. File No. 001-35211).
2.5	Closing Agreement, dated December 16, 2015, by and among Gastar Exploration Inc. and Husky Ventures, Inc., Silverstar of Nevada, Inc., Maximus Exploration, LLC and Atwood Acquisitions, LLC (incorporated by reference to Exhibit 2.3 of the Quarterly Report on Form 10-Q filed with the SEC on May 5, 2016. File No. 001-35211).
2.6**	Purchase and Sale Agreement, dated February 19, 2016, by and between Gastar Exploration Inc. and THQ Appalachia I, LLC (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on February 23, 2016. File No. 001-35211).
2.7	Amendment to Purchase and Sale Agreement, dated March 29, 2016, by and between Gastar Exploration Inc. and TH Exploration II, LLC (incorporated by reference to Exhibit 2.1 of the Current Report on Form 8-K filed with the SEC on March 30, 2016. File No. 001-35211).
2.8	Closing Agreement, dated April 7, 2016, by and between Gastar Exploration Inc. and TH Exploration II, LLC (incorporated by reference to Exhibit 2.6 of the Quarterly Report on Form 10-Q filed with the SEC on May 5, 2016. File No. 001-35211).
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	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. dated July 5, 2016 (incorporated by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q filed with the SEC on August 4, 2016. File No. 001-35211).
3.3	Amended and Restated Bylaws of Gastar Exploration Inc. dated November 4, 2015 (incorporated by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q filed with the SEC on November 5, 2015. File No. 001-35211).

3.4	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).
3.5	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 8-A filed on June 20, 2011. File No. 001-35211).
3.6	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).
3.7	Certificate of Designations of Series C Junior Participating Preferred Stock of Gastar Exploration Inc. (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on January 19, 2016. File No. 001-35211).
10.1	Amendment No. 9 to Second Amended and Restated Credit Agreement, dated October 14, 2016, by and among Gastar Exploration Inc., the Lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent for the lenders thereto, as collateral agent, as swing line lender and as issuing lender (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on October 20, 2016. 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
101.PRE†	XBRL Taxonomy Extension Presentation Linkbase Document

† 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.

** Pursuant to Item 601(b)(2) of Regulation S-K, the schedules and similar attachments 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.