Gastar Exploration Inc.
Form 10-K
March 09, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

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

Title of each class	Name of exchange on which registered
Common Stock, par value $0.001 per share	
8.625% Series A Cumulative Preferred Stock, par value $0.01 per share	NYSE MKT LLC
10.75% Series B Cumulative Preferred Stock, par value $0.01 per share	NYSE MKT LLC

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

None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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 Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

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

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

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

The aggregate market value of the voting and non-voting common equity of Gastar Exploration Inc. held by non-affiliates of Gastar Exploration Inc. as of June 30, 2016 (the last business day of Gastar Exploration Inc.'s most recently completed second fiscal quarter) was approximately $129.3 million based on the closing price of $1.10 per share on the NYSE MKT LLC.

The total number of shares of common stock, par value $0.001 per share, outstanding as of March 6, 2017 was 186,124,138.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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GASTAR EXPLORATION INC. AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2016

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Form 10-K") contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical fact included or incorporated by reference in this Form 10-K are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, future covenant compliance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "poter or "continue," the negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this Form 10-K are largely based on our expectations and beliefs concerning future developments and their potential effect on us, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends and other factors. Forward-looking statements may include statements that relate to, among other things, our:

- financial condition;
- cash flow and liquidity;
- timing and results of property divestitures;
- compliance with covenants under our indenture and credit agreements;
- 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. For a more detailed description of the known material factors that could cause actual results to differ from those in the forward-looking statements, see Item 1A. "Risk Factors" in Part I of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for oil, condensate, natural gas and NGLs;
- continued low or further declining prices for oil, condensate, natural gas and NGLs including risks of low commodity prices affecting the benefits of the Development Agreement (as defined below);
- our financial condition, results of operations, revenues, cash flows and expenses;

- the potential need to sell certain assets or raise additional capital;
- the need to take ceiling test impairments due to low 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;
- 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, market, develop and produce new oil and natural gas properties;
- uncertainties about the estimated quantities of oil and natural gas reserves and in the projection of future rates of production and timing of development expenditures of proved reserves;
- strength and financial resources of competitors;
- availability and cost of material and equipment, such as drilling rigs, service costs 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 oil or natural gas 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.

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

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

Unless otherwise indicated or required by the context, (i) for any date or period prior to the January 31, 2014 merger described above, "Gastar," the "Company," "we," "us," "our" and similar terms refer collectively to Gastar Exploration, Inc. (formerly known

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as Gastar Exploration Ltd.) and its subsidiaries, including Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.), and for any date or period after January 31, 2014, such terms refer collectively to Gastar Exploration Inc. and its subsidiaries, (ii) "Gastar USA" refers to Gastar Exploration USA, Inc., which, until January 31, 2014 was a first-tier subsidiary of Gastar Exploration, Inc. and its primary operating company, (iii) "Parent" refers to Gastar Exploration, Inc., (iv) all dollar amounts appearing in this Form 10-K are stated in United States dollars ("U.S. dollars") unless otherwise noted and (v) all financial data included in this Form 10-K have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP").

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Glossary of Terms

AMI	Area of mutual interest, an agreed designated geographic area where joint venturers or other industry partners have a right of participation in acquisitions and operations
Bbl	Barrel of oil, condensate or NGLs
Bcf	One billion cubic feet of natural gas
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
FASB	Financial Accounting Standards Board
Gross acres	Refers to acres in which we own 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
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
MMBoe	One million barrels of oil equivalent, calculated by converting natural gas volumes on the basis of 6 Mcf of natural gas per barrel
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
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
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
U.S. GAAP	Accounting principles generally accepted in the United States of America
WTI	West Texas Intermediate

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PART I

Item 1. Business

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 Meramec and Osage formations within the Mississippi Lime, the Oswego limestone, 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”). As of December 31, 2016, our remaining acreage position in the Appalachian Basin was approximately 15,400 gross (14,500 net) acres, of which 83% was undeveloped. We sold our remaining Appalachian Basin interests on January 20, 2017 (effective January 1, 2017) for approximately $200,000, before fees and expenses.

Shares of our common stock are listed on the NYSE MKT LLC under the symbol “GST,” shares of our 8.625% Series A Cumulative Preferred Stock are listed on the NYSE MKT LLC under the symbol “GST.PRA” and shares of our 10.75% Series B Cumulative Preferred Stock are listed on the NYSE MKT LLC under the symbol “GST.PRB”. Our principal office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, and our telephone number is (713) 739-1800. Our website address is http://www.gastar.com. Information on our website or about us on any other website is not incorporated by reference into and does not constitute part of this Form 10-K.

Our Strategy

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

- development and exploitation of our Mid-Continent assets in the STACK Play;
- the successful execution of our Drilling Program (as defined below) on certain of our STACK Play acreage in the Mid-Continent;
- active management of our drilling programs; and
- effective management, adoption and utilization of technological advancement.

Development and Exploitation of our Mid-Continent Assets in the STACK Play

After we sold a substantial portion of our Appalachian Basin assets in April 2016, we focused our activities in 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. We continued to build our acreage position in this region during 2013 through 2015 with our AMI co-participant, who prior to the closing of the Husky Acquisition (as defined below), handled all drilling, completion and production activities while we handled leasing and permitting activities in certain areas of the AMI. We also increased our exposure within the play through acquisitions of acreage and producing wells from subsidiaries of Chesapeake Energy Corporation and certain entities affiliated with its former chief executive officer and affiliates of Lime Rock Resources, respectively, during 2013. 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 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.

Our Mid-Continent development program was originally focused on using modern horizontal drilling and multi-stage fracture stimulation technologies to exploit the Hunton Limestone, a predominantly crude oil-bearing reservoir, which has been produced

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historically using vertical wells with conventional completion techniques. Since 2012, we, along with our former AMI co-participant acting as operator in the initial AMI and adjacent areas, drilled and completed 38 gross (17.9 net to Gastar) horizontal Hunton Limestone wells, representing the lowest known productive horizon of the STACK Play. As a result of the Husky Acquisition in late 2015, we operate each of these wells previously operated by our AMI co-participant. Commencing in 2013, we also drilled and completed 22 gross (21.4 net) Hunton Limestone wells as operator, including 17 gross (16.7 net) wells within the West Edmond Hunton Lime Unit (“WEHLU”).

During 2015, we began testing the potential of the Meramec formation within our Mid-Continent STACK Play acreage.

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, the Osage, a deeper bench of the Mississippi Lime located below the Meramec, the Woodford Shale, all ranging in depth from 6,000 to 9,000 feet, prospective plays in the shallower Oswego formation and the proven deeper Hunton limestone horizontal oil play. We believe that the STACK Play is one of the most economic plays in North America under current commodities prices and costs. 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 December 31, 2016, we held leases covering approximately 107,000 gross (83,800 net) acres in Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma, all of which we believe is prospective for one or several of the horizons comprising the STACK Play.

On October 14, 2016, we executed a definitive agreement with STACK Exploration LLC (the “Investor”) to jointly develop up to 60 Gastar operated wells in the STACK Play within a defined area of Kingfisher County, Oklahoma (the “Development Agreement”). The drilling program under the Development Agreement (the “Drilling Program”) will target the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 32,900 gross (19,100 net) undeveloped mineral acres under leases held by us. We will serve as 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 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 us 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.

After final reversion of each tranche (the “WI Tail”), the Investor has the right, but not the obligation, for a period of six months after final reversion to cause us to purchase the Investor’s WI Tail in the Drilling Program for such tranche (the “Investor Put Right”) for fair market value by applying the methodology to determine a 15% discounted present value as defined by the Development Agreement. If the Investor fails to exercise the Investor Put Right within the six-month period after achieving final reversion, then for a period of six months thereafter, we shall have the right, but not the obligation, to purchase the WI Tail from the Investor on the same fair market value approach of the Investor Put Right. If final reversion has not been achieved by the eighth anniversary of the spud date of the first well in a given tranche, Investor will, for a period of six months thereafter, have the right to cause us to buy Investor's then-current interest in such tranche at an agreed upon valuation.

We spudded our first operated STACK Play well, the Deep River 30-1H in the Meramec, in September 2015. To date, we have drilled and completed 11 gross (2.8 net) operated horizontal Meramec wells, of which nine gross (1.0 net) wells were drilled and completed under the Development Agreement, one gross (0.8 net) operated Osage well and one gross (0.8 net) operated Oswego well. In addition, we are currently drilling or completing nine gross (1.5 net) horizontal STACK Play wells, of which seven gross (0.5 net) wells are under the Development Agreement.

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To further test the potential of the STACK Play, to date, we have participated in the completion of seven gross (0.2 net) non-operated Meramec Shale wells, one gross (0.3 net) non-operated well targeting the Osage Shale, four gross (0.4 net) non-operated wells targeting the Oswego Limestone formation and three gross (0.1 net) non-operated Woodford Shale wells.

Actively Manage Our Drilling Program

We believe that dedicating the majority of our capital budget for 2017 to drilling and completing wells that we operate will enable us to control the timing and cost of our drilling and completion activities, as well as control operating costs and the marketing of our production. After the significant reduction in commodities prices experienced since mid-2014, control over our costs and expenditures has become increasingly important in achieving acceptable returns on capital investment. Our preliminary capital budget for 2017, which is dedicated exclusively to our STACK Play activities, is approximately $84.0 million, which includes $34.1 million for the planned drilling and completion of 14 gross (9.1 net) operated Osage wells, $5.1 million for our share of costs on 23 gross (2.3 net) operated Drilling Program wells, $3.3 million net costs for recompletion projects on producing operated wells in Oklahoma, $3.5 million for our participation in nine gross (0.9 net) non-operated STACK Play drilling, $30.8 million for maintaining our current Oklahoma leasehold position and $7.2 million for capitalized interest and administration costs. We may also seek opportunistic acquisitions of acreage positions in the STACK Play, with or without existing production, depending on the availability of capital and the quality and strategic importance of such acreage to our position.

We believe that we have assembled an experienced team of operating professionals with the specialized skills needed to plan and execute the drilling and completion of horizontal STACK Play wells.

Management, Adoption and Utilization of Technological Advancements

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

Oil and Natural Gas Activities

The following provides an overview of our major oil and natural gas projects during 2016. There is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled. For additional information regarding our sources of revenue and historical expenditures, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Mid-Continent Horizontal Oil Plays

We believe that our acreage is prospective in the STACK Play, an area of central Oklahoma that includes oil and natural gas-rich shale formations such as the proven Meramec formation, the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec, and the Woodford Shale, ranging in depth from 6,000 to 9,000 feet, and emerging prospective play in the shallow Oswego formation as well as the proven Hunton Limestone horizontal oil play. As of December 31, 2016, we held leases covering approximately 107,000 gross (83,800 net) acres in Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the STACK Play, all of which we believe is prospective for one or several of the horizons comprising the STACK Play.

Our leasing activities primarily located in northwest Kingfisher County, Oklahoma, began in 2012 initially with an AMI co-participant whom we bought out in the Husky Acquisition and assumed operatorship of the acquired wells in December 2015.

On October 14, 2016, we entered into the Development Agreement with the Investor to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma. See "—Development and Exploitation of our Mid-Continent Assets in the STACK Play" above for more information on the terms of the Development Agreement.

On July 6, 2015, we sold certain non-core assets comprised of 38 gross (16.7 net) wells producing approximately net 170 Boe/d (41% oil) for the three months ended March 31, 2015 and approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma for an adjusted purchase price of $46.5 million. The sale is reflected as a reduction to the full cost pool and we did not record a gain or loss related to the divestiture as it was not significant to the full cost pool.

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

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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 and with a property sale effective date of August 1, 2016 ("South STACK Play Acreage Sale"). On November 18, 2016, we and Red Bluff executed and delivered two amendments to the sale agreement and entered into a relating closing agreement, which, among other things, allocated $1.4 million of the purchase price to producing properties with the remainder of the purchase price to non-producing properties. As of December 31, 2016, we had received approximately $48.6 million of the South STACK Play Acreage Sale proceeds. Since December 31, 2016, we have received an additional $9.5 million of the South STACK Play Acreage Sales proceeds, bringing the total net sales proceeds received to date to $58.1 million. We anticipate receiving an additional $12.7 million of South STACK Play Acreage Sale proceeds by July 2017, subject to certain adjustments.

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

Well Name	Current Working Interest(1)	Approximate Lateral Length (in feet)	Peak Production Rates(2) (Boe/d)	Boe/d(3)	% Oil(4)	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Meramec Completions							
Holiday Road 2-1H(6)	78.3%	4,300	654	230	74%	April 11, 2016	$ 4.0
Ingle 29-1H(5)	16.5%	4,900	1,037	612	75%	October 22, 2016	$ 5.2
Geis 31-1H(5)	11.6%	4,900	877	490	76%	October 31, 2016	$ 3.8
Katy 21-1H(5)	13.6%	4,900	N/A	327	69%	November 17, 2016	$ 4.0
Lilly 28-1H(5)(6)	12.7%	4,400	N/A	581	89%	December 2, 2016	$ 4.5
Mott 19-1H(5)	8.9%	4,500	N/A	68	84%	January 8, 2017	$ 4.5
Mott 20-2H(5)	13.8%	5,000	N/A	734	80%	January 10, 2017	$ 4.4
Victoria 25-1H(5)	12.0%	4,600	N/A	490	71%	January 11, 2017	$ 4.4
Kramer 29-1H(5)	9.3%	4,400	N/A	624	89%	January 23, 2017	$ 5.0
Ma Stucki 30-1H(5)	2.9%	4,800	N/A	N/A	N/A	March 2, 2017	$ 4.2
Best 20-1H(5)	3.9%	4,900	N/A	N/A	N/A	Completing	$ 4.5
Eldon 34-1H(5)	7.7%	4,800	N/A	N/A	N/A	Waiting on Completion	$ 4.5
Snowden 27-1H(5)	11.8%	5,100	N/A	N/A	N/A	Waiting on Completion	$ 5.5
Bradbury 28-1H(5)	7.5%	7,300	N/A	N/A	N/A	Drilling	$ 6.6
Pickle 33-1H(5)	6.2%	5,100	N/A	N/A	N/A	Waiting on Completion	$ 4.5
Johnny 32-1H(5)	5.0%	4,900	N/A	N/A	N/A		$ 4.5

						Waiting on Completion	
Osage Completions							
McGee 29-1H(6)	81.0%	4,200	414	211	72%	September 25, 2016	$ 4.3
Great Divide 1-12H(5)	7.5%	5,000	N/A	N/A	N/A	Completing	$ 3.5
Hane 14-1H	35.0%	4,900	N/A	N/A	N/A	Drilling	$ 3.5
Pedlik 10-1H	65.0%	4,900	N/A	N/A	N/A	Drilling	$ 3.5
Oswego Completions							
Tomahawk 7-1H	79.3%	4,200	418	87	90%	September 24, 2016	$ 2.7

(1) Current estimated working interest. Working interest subject to change based on final force pooling orders.
(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 February 28, 2017.
(4) Represents percent oil produced inception to date.
(5) Drilling Program well. Working interest reflected is our total current working interest after Development Agreement impact.
(6) Excludes one-time fishing or coring costs.

To further test the potential of other Mid-Continent STACK Play formations, to date, we have participated in the completion of seven gross (0.2 net) non-operated Meramec Shale wells, one gross (0.3 net) non-operated well targeting the Osage Shale, four gross (0.4 net) non-operated wells targeting the Oswego Limestone formation and three gross (0.1 net) non-operated Woodford Shale wells.

At December 31, 2016, proved reserves attributable to the Mid-Continent were approximately 25.6 MMBoe, a 38% decrease from year-end 2015 reserves of 41.0 MMBoe. The 30.3 MMBoe decline in proved reserves from year-end 2015 is primarily the result of the sale of 14.9 MMBoe of proved reserves, the majority of which related to the sale of our assets in the Appalachian Basin and

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16.2 MMBoe related to negative reserve revisions partially offset by extensions and discoveries exceeding production. The reserve revisions primarily resulted from the removal of Hunton PUD locations as we now focus our capital activity on drilling Meramec and Osage wells to hold acreage by production and delineate our STACK Play position. As of December 31, 2016, Mid-Continent proved reserves represented 100% of our total proved reserves and SEC total proved PV-10 value. Total Mid-Continent proved reserves at year-end 2016 were comprised of approximately 75% of oil, condensate and NGLs reserves compared to 78% at year-end 2015. Approximately 51% and 33% of the Mid-Continent year-end 2016 and year-end 2015 reserves were proved developed, respectively.

For 2017, our focus is to drill in areas that we believe will result in de-risking of additional acreage within the STACK Play and hold by production near-term expiring acreage.

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

	For the Years Ended December 31,		
Mid-Continent	2016	2015	2014
Production:			
Oil and condensate (MBbl)	1,058	1,182	792
Natural gas (MMcf)	3,818	3,370	2,822
NGLs (MBbl)	503	433	332
Total Production (MBoe)	2,198	2,177	1,594
Oil and condensate (MBbl/d)	2.9	3.2	2.2
Natural gas (MMcf/d)	10.4	9.2	7.7
NGLs (MBbl/d)	1.4	1.2	0.9
Total daily production (MBoe/d)	6.0	6.0	4.4
Average sales price per unit(1):			
Oil and condensate (per Bbl)	$40.12	$46.18	$88.84
Natural gas (per Mcf)	$2.21	$2.57	$4.24
NGLs (per Bbl)	$13.94	$13.15	$31.79
Average sales price per Boe(1)	$26.35	$31.67	$58.27
Selected operating expenses (in thousands):			
Production taxes	$1,601	$1,444	$2,940
Lease operating expenses	$19,703	$19,270	$15,112
Transportation, treating and gathering	$1,086	$14	$40
Selected operating expenses per Boe:			
Production taxes	$0.73	$0.66	$1.84
Lease operating expenses	$8.96	$8.85	$9.48
Transportation, treating and gathering	$0.49	$0.01	$0.02
Production costs(2)	$9.46	$8.86	$9.50

(1) Excludes the impact of hedging activities.
(2)

Production costs include lease operating expense (“LOE”), insurance, transportation, treating and gathering and workover expense and excludes ad valorem and severance taxes.

Appalachian Basin

Due to the continued depressed commodity 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 December 31, 2016, our acreage position in the play was approximately 15,400 gross (14,500 net) acres, of which 83% was undeveloped. On January 20, 2017, we sold our remaining interest in producing assets and leasehold in the Appalachian Basin, effective January 1, 2017, for $200,000, before fees and expenses.

At December 31, 2016, there were no economic proved reserves attributable to the Appalachian Basin.

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

Appalachian Basin	For the Years Ended December 31, 2016	2015	2014
Production:			
Oil and condensate (MBbl)	47	243	182
Natural gas (MMcf)	2,327	10,389	8,776
NGLs (MBbl)	236	779	469
Total production (MBoe)	671	2,753	2,114
Oil and condensate (MBbl/d)	0.1	0.7	0.5
Natural gas (MMcf/d)	6.4	28.5	24.0
NGLs (MBbl/d)	0.6	2.1	1.3
Total daily production (MBoe/d)	1.8	7.5	5.8
Average sales price per unit(1)(2):			
Oil and condensate (per Bbl)	$11.73	$16.78	$68.21
Natural gas (per Mcf)	$1.04	$0.79	$4.06
NGLs (per Bbl)	$1.00	$1.85	$23.11
Average sales price per Boe(1)(2)	$4.76	$4.99	$27.89
Selected operating expenses (in thousands):			
Production taxes(3)	$307	$1,433	$3,794
Lease operating expenses(3)	$900	$4,457	$4,211
Transportation, treating and gathering(3)	$618	$2,175	$3,639
Selected operating expenses per Boe:			
Production taxes(3)	$0.46	$0.52	$1.79
Lease operating expenses(3)	$1.34	$1.62	$1.99
Transportation, treating and gathering(3)	$0.92	$0.79	$1.72
Production costs(4)	$2.21	$1.92	$3.35

(1) Excludes the impact of hedging activities.

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

	For the Year Ended December 31, 2014
Appalachian Basin	
Average sales price per unit:	
Oil and condensate (per Bbl)	$ 50.96
Natural gas (per Mcf)	$ 3.14
NGLs (per Bbl)	$ 24.55

Average sales price per Boe	$ 22.87

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

	For the Year Ended December 31, 2014
Appalachian Basin	
Selected operating expenses per Boe:	
Production taxes	$ 1.52
Lease operating expenses	$ 2.08
Transportation, treating and gathering	$ 0.97

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

	For the Year Ended December 31, 2014
Appalachian Basin	
Selected operating expenses per Boe:	
Production costs	$ 2.69

Markets and Customers

The success of our operations is dependent primarily upon prevailing and future prices for oil, condensate, natural gas and NGLs. The markets for oil, condensate, natural gas and NGLs have historically been and currently continue to be volatile. Oil, condensate, natural gas and NGLs prices are beyond our control. The prices we receive for our oil, condensate, natural gas and NGLs production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy, foreign imports, political conditions in other petroleum producing countries, the actions of the Organization of Petroleum Exporting Countries, domestic regulation, legislation and policies. Decreases in the prices we receive for our oil and natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, our revenue, profitability and cash flow from operations. For additional information regarding the prices we receive for our oil, condensate, natural gas and NGLs production, see Item 1A. “Risk Factors - Oil, condensate, natural gas and NGLs prices are volatile. Substantial declines in commodity prices have significantly and negatively affected our financial condition and results of operations.”

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

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

The following table provides information regarding our significant customers whom accounted for more than 10% of our oil, condensate, natural gas and NGLs revenues, excluding hedge impact, for the periods indicated:

	For the Years Ended December 31,		
	2016	2015	2014
Sunoco	67 %	62 %	37 %
Superior	12 %	6 %	5 %
SEI(1)	5 %	22 %	50 %

(1) SEI filed for Chapter 7 bankruptcy on June 3, 2016.

Sunoco Logistics Partners L.P. ("Sunoco") purchases the majority of our Mid-Continent oil production. Superior Pipeline Company ("Superior") purchases the majority of our natural gas and NGLs production. There are numerous purchase and transportation alternatives currently available in the Mid-Continent so in the event that Sunoco or Superior were to cease purchasing and transporting our oil, condensate, natural gas and NGLs production, our ability to conduct normal operations would not be significantly restricted. Prior to its bankruptcy filing in June 2016, SEI Energy, LLC ("SEI") purchased the majority of our Appalachian Basin production. For more information, see Item 1A. "Risk Factors-Our ability to market our oil, condensate, natural gas and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our oil, condensate, natural gas and NGLs."

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Competition

The oil and natural gas industry is intensely competitive in all of its phases. We encounter competition from other oil and natural gas companies in all areas of our operations. In seeking suitable oil and natural gas properties for acquisition, we compete with other companies operating in our areas of interest, including large oil and natural gas companies and other independent operators, many of whom have greater financial resources and, in many instances, have been engaged in the exploration and production business for a much longer time than we have. Many of our competitors also have substantially larger operating staffs than we do. Many of these competitors not only explore for and produce oil and natural gas but also market oil and natural gas and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and define, evaluate, bid for and purchase a greater number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. For more information, see Item 1A. "Risk Factors-Competition in the oil and natural gas industry is intense. We are smaller and have less operating history than many of our competitors, and increased competitive pressure could adversely affect our results of operations."

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

Seasonal Nature of Business

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

U.S. Governmental Regulation

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

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

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

Regulation of Exploration and Production

Regulation of Production

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

Oklahoma Forced Pooling Laws

We rely upon the Oklahoma "forced pooling" laws and regulations to increase our working interest in drilling units, or increase the participation levels in a proposed well to render the project economic, for wells we propose to drill as operator in the STACK Play. Any such increase in working interest would lead to a proportionate increase in our share of the production and reserves associated with any such successfully drilled well. Under Oklahoma law, if a party proposes to drill the initial well to a particular formation in a specific drilling and spacing unit but cannot obtain the agreement of all other oil and natural gas interest holders and other leaseholders within the unit as to how the unit should be developed, the party may commence a "forced pooling" process. Under current regulations, the proposed operator is required to demonstrate in an administrative proceeding that it has made a good faith effort to bargain with all of the respondents prior to filing its application. The fair market value of the mineral interests in the unit is determined in the administrative proceeding by reference to market transactions involving nearby oil and natural gas rights, especially what has been paid for mineral leases in the particular drilling and spacing unit and the immediately surrounding drilling and spacing units.

Assuming the application is granted and a forced pooling order is granted, the respondents then have 20 days to elect either to participate in the proposed well or accept fair market value for their interest, usually in the form of a cash payment, an overriding royalty, or some combination, based on the fair market value established and approved through the administrative hearing. The pooling order usually also addresses the time frame for drilling the well and provides for the manner in which future wells within the unit may be drilled. The applicant for the pooling order is ordinarily designated as the operator of the wells subject to the pooling order.

The availability of forced pooling makes it difficult for a small number of owners to block or delay the drilling of a particular well proposed by another interest holder. Exploration and production companies in Oklahoma often negotiate to lease as much of the mineral interests in a particular area as are readily available at acceptable rates, and then use the forced pooling process to proceed with the desired development of the well. Due to increased interest in the STACK Play as an economic play in the current price and cost environment, however, third party interest holders may be more likely to bear their proportionate share of the costs of the proposed future wells on our acreage.

Regulation of Sales of Natural Gas

The price at which we buy and sell natural gas is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the Federal Energy Regulatory Commission ("FERC") and/or the Commodity Futures Trading Commission ("CFTC"). See the discussion below of "- Other Federal Laws and Regulations Affecting Our Industry – Energy Policy Act of 2005". Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities. In addition, we would be required to annually report to FERC on May 1 of each year information regarding natural gas purchase and sale transactions if we have purchase or sale transactions that contribute or may contribute to the formation of a gas index during the prior calendar year in excess of 2.2 million MMBtu. See the discussion below of "- Other Federal Laws and Regulations Affecting Our Industry – FERC Market Transparency Rules."

Regulation of Availability, Terms and Cost of Pipeline Transportation

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

The ability of our facilities to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and

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interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives headed by the Natural Gas Council (the “NGC+ Work Group”), or to explain how and why their tariff provisions differ. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group’s interim guidelines for such an interconnecting pipeline.

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

Other Federal Laws and Regulations Affecting Our Industry

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

FERC Market Transparency Rules. Under FERC regulations, wholesale buyers and sellers of physical natural gas are required to report on Form No. 552 on May 1 of each year aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year in excess of 2.2 million MMBtu to the extent such transactions utilize, contribute to or may contribute to the formation of price indices.

Additional proposals and proceedings that might affect the natural gas industry are pending or are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. We do not believe that we will be affected by any action taken in a materially different way than other natural gas producers, gatherers and marketers with which we compete.

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

In a number of instances, however, the ability to transport and sell such products on interstate pipelines is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate

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

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

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

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

U.S. Environmental and Occupational Safety and Health Regulation

Our oil and natural gas exploration, development and production operations, and similar operations that we do not operate but in which we own a working interest, are subject to stringent federal, tribal, regional, state and local environmental laws and regulations governing worker safety and health, environmental protection and the discharge of substances into the environment. Numerous governmental agencies, including the U.S. Environmental Protection Agency ("EPA"), the U.S. Occupational Safety and Health Administration ("OSHA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause us to incur significant capital expenditures on costly actions to achieve and maintain compliance. These laws and regulations may, among other things, require the acquisition of permits, including drilling permits, before conducting regulated activities; restrict the types, quantities and concentrations of various substances that may be released into the environment as a result of natural gas and oil drilling, production and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; restrict injection of produced water or other regulated fluids into subsurface strata that may contaminate groundwater or result in seismic incidents; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; impose specific safety and health criteria addressing workforce protection; and impose liabilities for pollution resulting from our operations. Failure to comply with these environmental and worker health and safety laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects, or the issuance of injunctions limiting or prohibiting operations in affected areas.

The trend in environmental legislation and regulation is toward stricter standards to place more restrictions and limitations on activities that may adversely affect the environment. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results. If substantial liabilities to third parties or governmental entities for environmental claims are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Moreover, a serious incident of pollution arising from our operations may result in our being liable for material remedial costs and damages to natural resources or properties as well as the suspension or cessation of our operations in the affected area. Although we maintain insurance coverage against costs of certain clean-up operations, no assurance can be given that we have insurance or are fully insured against all such potential risks. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

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

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the Superfund law, and analogous state laws impose strict, joint and several liability without regard to fault or legality of conduct on persons who are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the site where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substance released at the site. Under CERCLA, these “responsible parties” may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for

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neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although CERCLA currently excludes, among other things, petroleum, natural gas and NGLs from the definition of hazardous substance, our operations as well as other operations in which we own a working interest generate materials that are subject to regulation as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act ("RCRA") and comparable state laws regulate the generation, treatment, storage, transportation, disposal and clean-up of hazardous and non-hazardous wastes. Our operations, and other operations in which we own a working interest, generate wastes, including hazardous wastes that are subject to RCRA and comparable state laws. Although RCRA currently excludes certain oil and natural gas exploration, development and production wastes from the definition of hazardous waste, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we cannot assure that this exclusion will be preserved in the future. For example following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any removal of this exclusion could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the oil and natural gas industry in general.

Moreover, there have been public concerns expressed about NORM being detected in flow back water resulting from hydraulic fracturing. NORM is subject primarily to individual state radiation control regulations while NORM handling and management activities are governed by regulations promulgated by OSHA. These state and federal regulations impose certain requirements concerning worker protection with respect to NORM as well as the treatment, storage and disposal of such flow back water generated from these activities. Concern over NORM in general, or NORM in groundwater in particular, could result in further regulation in the treatment, storage, handling and discharge of flow back water generated from oil and natural gas activities, including hydraulic fracturing, that, if implemented, could limit drilling or increase the costs of drilling in affected regions.

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

Water Discharges and Subsurface Injections

Our operations and other operations in which we own a working interest are subject to the Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), and analogous state laws. These laws and their implementing regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including oil and hazardous substances, into waters of the United States and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The EPA has issued final rules attempting to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and numerous district courts ponder lawsuits opposing implementation of the rule. In January 2017, the U.S. Supreme Court accepted review of the final rule to determine whether jurisdiction rests with the federal district or appellate courts. Litigation surrounding this rule is on-going. On February 28, 2017, President Trump issued an executive order directing the EPA and the U.S. Corps of Engineers to review and, consistent applicable law, initiate rulemaking to rescind or revise the rule. With issuance of this executive order, it remains uncertain what actions, if any, the government will take in the pending litigation regarding the final rule and what the results of the review by the EPA and the U.S. Corps of Engineers will be.

The Oil Pollution Act of 1990 (“OPA”) amends the CWA and sets standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Our oil and natural gas exploration, development and production operations, and other operations in which we own a working interest, generate produced water, drilling muds and other waste streams, some of which may be disposed by injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the Safe Drinking Water Act (“SDWA”) and analogous state laws. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected, and prohibits the migration of fluids containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages and personal injuries.

Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, Oklahoma, where we conduct operations, issued new rules for injection wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on injection wells in proximity to faults and also, from time to time, developed and implemented plans directing certain wells where seismic incidents have occurred to restrict or suspend injection well operations. The Oklahoma Corporation Commission (“OCC”) has implemented a variety of measures including adopting the National Academy of Science’s “traffic light system,” pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted and, further, evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. The OCC also has established rules requiring operators of certain saltwater disposal wells in seismically-active areas, or Areas of Interest, within the Arbuckle formation of the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells’ depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within Areas of Interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. As a result of these measures, the OCC from time to time has developed and implemented plans calling for injection wells within Areas of Interest where seismic incidents have occurred to restrict or suspend disposal operations in an attempt to mitigate the occurrence of such incidents.

Also, ongoing lawsuits allege that injection well disposal operations have caused damage to neighboring properties or otherwise violated state and federal rules governing waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and natural gas activities utilizing injection wells for produced water disposal. Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of produced water into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where produced water injection activities occur or are proposed to be performed. Court decisions or the adoption of any new laws, regulations, or directives that restrict our ability to dispose of saltwater generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas

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commissions or similar state agencies, but several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA issued Clean Air Act (“CAA”) final regulations in 2012 and in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting; published in June 2016 an effluent limited guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management (“BLM”) published a final rule in March 2015 establishing more stringent standards for performing hydraulic fracturing on federal and Indian lands but in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government.

The U.S. Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate or where we own a working interest, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Air Emissions

The CAA and comparable state laws and regulations govern emissions of various air pollutants through air emissions standards, construction and operating permit programs and the imposition of other compliance requirements. Air emissions from some equipment found at our operations or other operations in which we own an interest, such as gas compressors, are potentially subject to regulations under the CAA or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. Any need to obtain air emissions permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA is required to make attainment and non-attainment designations for specific geographic locations under the revised standards and states may be required to implement more stringent regulations that could apply to our operations and require the installation of new emissions controls, resulting in longer permitting timelines and cause significant increases in our capital or operating expenditures, any of which developments could adversely impact our business.

Climate Change

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases (“GHGs”). These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has , however, adopted rules under authority of the CAA that, among other things, establish permitting reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting "best available control technology" standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations.

Federal agencies also have begun directly regulating emissions of methane from oil and natural gas operations. In June 2016, the EPA published New Source Performance Standards (“NSPS”), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. Moreover, in November 2016, the EPA issued an Information Collection

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Request (“ICR”) seeking information about methane emissions from facilities and operators in the oil and natural gas industry but on March 2, 2017, the EPA announced it was withdrawing the ICR so that the agency may further assess the need for the information that it was collecting through the request. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France in preparing an agreement requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris agreement” was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise limit emissions of GHGs from, our equipment and operations, or the equipment and operations of assets in which we own an interest, could require us to incur costs to reduce emissions of GHGs associated with those operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such physical effects were to occur, they could have an adverse effect on our exploration, development and production interests and operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Endangered Species Act

The federal Endangered Species Act (“ESA”) and similar state laws and other regulatory initiatives restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species and, in these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species or be prohibited from conducting operations during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of one or more settlements entered into by the U.S. Fish and Wildlife Service, the agency is required to make determinations on the listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could impair our ability to timely complete well drilling and development and could cause us to incur additional costs arising from species protection measures or become subject to operating restrictions or bans in the affected areas, which delays, costs or restrictions may be significant. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Worker Safety and Health

We are subject to the requirements of OSHA and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to- Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Operations on Federal Lands

Performance of oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, may be subject to the National Environmental Policy Act ("NEPA"). The NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. The NEPA review process may take a significant amount of time and is subject to challenges by environmental groups, which have the potential to delay current and future projects. Our current and proposed exploration, development and production activities upon federal lands require governmental permits that are subject to the requirements of NEPA. We are not currently planning any drilling operations on BLM leased acreage in 2017. Our future development of any project on BLM leased acreage will be subject to completion of these environmental assessments and any delays in such completion could result in delays in our exploration or production programs. Permit

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authorizations under NEPA are subject to protests, appeal or litigation, any or all of which may also delay or halt projects. Moreover, depending on the mitigation strategies recommended in the environmental assessments, we could incur added costs, which could be substantial.

Other Laws and Regulations

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

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. For additional information relating to our disclosure of revenues, profits and total assets in the segment in which we operate, please see Item 6. "Selected Financial Data" and Item 8. "Financial Statements and Supplementary Data," each included in this Form 10-K.

Filings of Reserve Estimates with Other Agencies

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

On December 16, 2011, the applicable provincial commissions in Canada issued a decision document which granted us exemptive relief from the disclosure requirements contained in NI 51-101. As a result, we are no longer required to comply with the requirements of NI 51-101 and accordingly, are not required to file Form 51-101F1, "Statement of Reserves Data and Other Oil and Gas Information," revised Form 51-101F2, "Report of Reserve Data by Independent Qualified Reserves Evaluator," and revised Form 51-101F3, "Report of Management and Directors on Oil and Gas Disclosure." In lieu of such filings, we are permitted to provide disclosure with respect to our oil and gas activities in the form permitted by, and in accordance with, the legal requirements of the Securities Act, the Exchange Act and the rules and regulations of the SEC and the NYSE MKT. We are required to file such disclosure on SEDAR as soon as practicable after such disclosure is filed with the SEC.

Insurance Matters

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

We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law nor would it cover a gradual pollution loss. We carry limited property insurance. Our control of well limits are based upon our assessment of the risk and consideration of the cost of the insurance. See Item 1A. "Risk Factors-The process of drilling for and producing oil and natural gas involves many operating risks that can cause substantial losses, and we may not have enough insurance to cover these risks adequately."

Employees

As of March 6, 2017, we had 45 employees, all of whom are full time. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, regulatory reporting, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our oil

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and natural gas. Our employees do not belong to a union or have a collective bargaining organization. Management considers its relationship with its employees to be good.

Corporate Offices

Our corporate office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, where we lease 12,823 square feet. Additionally, we lease 7,002 square feet of office space in Oklahoma City, Oklahoma.

Available Information

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

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

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

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

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

Item 1A. Risk Factors

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

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

Oil, condensate, natural gas and NGLs prices are volatile. Substantial declines in commodity prices have significantly and negatively affected our financial condition and results of operations.

The success of our business depends primarily on the market prices of oil, condensate, natural gas and NGLs. Oil, condensate, natural gas and NGLs prices are set by broad market forces, which have been and will likely continue to be volatile in the future. Since the second half of 2014, commodity prices have declined precipitously as a result of several factors, including increased worldwide supplies, a stronger U.S. dollar, weather factors, a strong competition among oil producing countries for market share and decreased demand in emerging markets, such as China. Specifically, WTI prices declined from a monthly average of $101.68 per barrel in June 2014 to a monthly average of $27.08 per barrel in February 2016. Subsequent to February 2016, WTI prices have increased to a monthly average of $48.69 per barrel in December 2016. The Henry Hub spot market price of natural gas declined from a monthly average of $5.86 per MMBtu in February 2014 to a monthly average of $1.69 per MMBtu in March 2016 and has subsequently increased to a monthly average of $3.57 per MMBtu in December 2016. The continued depressed commodity prices adversely

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affected our 2016 financial condition and results of operations and contributed to a reduction in our anticipated future capital expenditures. In addition, this decline in commodity prices adversely impacted our estimated proved reserves and resulted in an impairment to our oil and natural gas properties during the first quarter of 2016.

Lower realized prices also may reduce the amount of oil, condensate, natural gas or NGLs that we can produce economically. Prices for oil, condensate, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil, condensate, natural gas or NGLs, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to:

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

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

- Adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations and our ability to meet our financial covenants under our debt agreements;
- Reducing the amount of oil, condensate, natural gas and NGLs that we can produce economically;
- Causing us to delay or postpone some of our capital projects;
- Reducing our revenues, operating income or cash flows;
- Reducing the amounts of our estimated proved oil and natural gas reserves;
- Reducing the carrying value of our oil and natural gas properties;
- Reducing the standardized measure of discounted future net cash flows relating to oil and natural gas reserves;
- Reducing or eliminating our ability to pay cash dividends on our outstanding preferred stock; and
- Limiting our access to sources of capital, such as equity and long-term debt.

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

Regional oil, condensate, natural gas and NGLs prices may move independently of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing.

We are highly leveraged and may not be able to generate sufficient cash or cash flows, as applicable, to service all of our indebtedness 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 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 recent $250.0 million senior secured first lien term loan facility (the “Term Loan”) and our $125.0 million Convertible Notes due 2022 (the “Notes”), depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control, as well as our ability to complete pending and proposed asset sales. As of March 6, 2017, our cash balance was

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approximately $42.6 million. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the Notes.

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;
- 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.

Our ability in the future to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our Notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our Term Loan 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 repayments of amounts owed under our Term Loan as a result of such dispositions. 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.

If our stockholders do not approve the conversion rights under our recently issued $125.0 million of Notes by July 3, 2017, we will incur significant additional interest expense, which could adversely affect the Company.

Our recently issued $125.0 million of Notes are convertible at the option of the holder into our common stock only if holders of issued and outstanding common stock (other than shares recently issued to funds managed by affiliates of Ares) approve the conversion rights of the Notes on or before July 3, 2017 in a manner satisfactory to meet the requirements of The NYSE MKT (the “Requisite Stockholder Approval”). There is no assurance the Requisite Stockholder Approval will be obtained. If the Requisite Stockholder Approval is not obtained by July 3, 2017, the Notes will not become convertible and the interest rate payable on the Notes will increase to 15.0% per annum, up to 7.0% per annum of which is payable in kind through the issuance of additional Notes in the principal amount of such interest at the option of the Company. This would result in up to $11.25 million per year in additional interest expense and would reduce cash available for capital expenditure programs and other business uses, which could have an adverse effect on the Company.

Additionally, if we do not timely receive Requisite Stockholder Approval, then upon any default under the Notes that results in acceleration of the Notes, the holders of the Notes will be entitled to a “make-whole” premium based on the present value of remaining payments of principal and interest (assuming a 15.0% per annum rate) in addition to principal and unpaid interest. The amount of any such make-whole premium could be substantial and would reduce our assets available to satisfy other creditors or equity holders.

The covenants in our Term Loan and Notes will restrict us from paying cash dividends on our outstanding preferred stock after August 1, 2018, unless we meet a fixed charge coverage ratio test, and we may not be able to pay such dividends in the future.

There is no assurance when or if we will be able to pay cash dividends, including accumulated and unpaid dividends, on our outstanding two series of preferred stock in the future. To be able to pay such dividends, we must meet a fixed charge coverage ratio of not less than 1.0 to 1.0 from August 1, 2018, to, but excluding May 1, 2019 and of not less than 1.25 to 1.0 from and after May 1, 2019. We may in the future, in lieu of cash dividends, elect to pay accumulated and unpaid dividends on our outstanding preferred stock by issuing shares of our common stock, as provided in the certificates of designation of rights and preferences setting forth the terms of our outstanding Series A Preferred Stock and Series B Preferred Stock, which issuance will dilute our existing common

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shareholders. If we fail to pay full cash dividends in four quarters, whether consecutive or non-consecutive, then holders of our outstanding Series A and Series B Preferred Stock, voting as a single class, will also have the right to elect up to two directors to the board of directors of the Company.

Our development operations will require substantial capital expenditures in order to grow or maintain our production levels. Our limited access to the funds for necessary future growth and maintenance capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay cash dividends to our preferred stockholders and to make required payments on our indebtedness.

The oil and natural gas industry is capital intensive. We expect to make substantial growth and maintenance capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. These expenditures reduce the amount of cash available for distribution to our preferred stockholders and to service our indebtedness. Our preliminary capital budget for 2017 totals approximately $84.0 million, including capitalized costs, which we expect to fund these expenditures using existing cash balances, recent financing activities and cash generated internally from our operations.

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

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

In the current oil and natural gas price environment, our sources of capital are constrained. Our failure to obtain the funds for capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay cash dividends to our preferred stockholders and to service our indebtedness. Further, the Indenture governing our Notes and the agreement governing our Term Loan restrict us from incurring additional borrowings. Even if we are successful in obtaining additional borrowings, the terms of such financings could be highly dilutive to our equity or be available only at significantly higher interest rates. These funds, if available, may limit or prohibit paying cash dividends to our preferred stockholders and to service our indebtedness. In addition, incurring additional debt will increase our already significant financial leverage.

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

With the exception of the one-time sale of our Australian properties in 2009, recognition of a $27.7 million non-cash gain on acquisition of assets at fair value for the Chesapeake Energy Corporation acquisition, and subsequent sale of certain properties acquired from Chesapeake, which resulted in net income of $40.0 million in 2013, and recognition of a $23.9 million gain attributable to the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement which resulted in net income of $36.5 million in 2014, we have not been profitable since we started our business. Our capital has been employed in an increasingly expanding oil and natural gas exploration and development program, with our focus on finding significant oil and natural gas reserves and producing from them over the long-term rather than focusing on achieving immediate net income. The uncertainties described in this Item 1A. “Risk Factors” and elsewhere in this Form 10-K may impede our ability to ultimately find, develop, exploit or maintain our oil and natural gas reserves. Our failure to achieve profitability in the future could materially adversely affect our ability to raise additional capital and continue our exploration and development program.

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

We have entered into NYMEX futures contracts as hedges on approximately 644,000 Bbls of crude production and 2.3 Bcf of natural gas production in 2017 and 103,000 Bbls of crude production and 1.8 Bcf of natural gas production in 2018 as of December 31, 2016. In light of recent significant declines in oil and natural gas prices, the continued benefit these hedges provide

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will diminish should energy commodities futures market pricing improve. In addition, the use of these arrangements also may limit our ability to benefit from significant increases in the prices of oil, condensate, natural gas and NGLs.

Any disruptions in production, development of proved oil and natural gas reserves, or our ability to process and sell oil, condensate, natural gas and NGLs from our properties in the Mid-Continent would have a material adverse effect on our results of operations or reduce future revenues.

Our current production is geographically concentrated in the Mid-Continent.

Approximately 95% of our oil, condensate, natural gas and NGLs revenues, before the impact of hedges, and approximately 100% of our total proved reserves for the year ended December 31, 2016 were attributable to our properties in the Mid-Continent. Production in the Mid-Continent could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems or governmental actions limiting or shutting-in production.

Our producing properties are concentrated in the Mid-Continent, making us vulnerable to risks associated with operating in one major geographic area.

Following the completion of our Appalachian Basin Sale, our producing properties and all of our proved reserves are geographically concentrated in the Mid-Continent, with a particular concentration in Oklahoma. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by and costs associate with governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, natural disasters such as earthquakes or weather related conditions or interruption of the processing or transportation of oil, condensate, natural gas or NGLs and changes in regional and local political regimes and regulations. Such conditions could have a material adverse effect on our financial condition and results of operations.

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

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

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

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

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

Approximately 49% of our proved reserves are classified as proved undeveloped at December 31, 2016 and may ultimately prove to be less than current reserves estimates.

At December 31, 2016, approximately 49% of our total proved reserves were classified as proved undeveloped and all were located in the Mid-Continent. It will take approximately $111.7 million of capital to drill our undeveloped locations over the next five years. Our estimate of proved reserves at December 31, 2016 assumes that we will spend in 2017 and 2018 development capital expenditures to develop these reserves of $385,000 and $26.2 million, respectively. Further, our drilling efforts may be delayed or unsuccessful and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows and our results of operations. Absent significant price increases, the sustained lower oil and natural gas prices experienced since the middle of 2014 will continue to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn may make it more likely that we will incur impairment charges in the future against our oil and natural gas properties under full cost accounting. In addition, oil and natural gas prices sustained at current or lower levels and the resultant impact such prices may have on our drilling economics and our ability to raise capital could require us to re-evaluate and postpone our development drilling, which could result in the reduction of some of our proved undeveloped reserves.

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

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

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

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

- Unexpected drilling conditions;
- Blowouts, fires or explosions with resultant injury, death or environmental or natural resource damages;
- Pressure or irregularities in formations;
- Environmental hazards, such as natural gas leaks, crude oil spills, pipeline and tank ruptures, encountering NORM and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the

environment;
- Uncontrollable flows of natural gas, oil, brine water or drilling fluids;
- Equipment failures or accidents;
- Natural disasters such as earthquakes;
- Adverse weather conditions;

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- Compliance with existing and any future governmental laws and regulations, including environmental requirements;
- Shareholder activism and activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas; and
- Shortages or delays in the availability of drilling rigs and the delivery of equipment or obtaining water for hydraulic fracturing operations.

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

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

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

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

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

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

You should not consider the present values of estimated future net cash flows referred to in this Form 10-K to be the current market value of the estimated reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves for all periods from 2013 to 2016 are based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect when the estimate is made. Current or actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

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

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In this report, the net present value of estimated future net revenues of our proved reserves at December 31, 2016 is calculated using the historical 12-month unweighted arithmetic average of the first-day-of-the-month prices which are substantially above current oil and natural gas prices. These average prices and the 10% discount rate are not necessarily the most appropriate price or discount factor based on prices and interest rates in effect from time to time and risks associated with our reserves or the oil and natural gas industry in general.

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

Under the full cost method of accounting, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. We may continue to experience write downs of the carrying value of our oil and natural gas properties in the future if the present value of our proved oil and natural gas reserves is lower than our remaining unamortized capitalized costs. If the net capitalized costs of our oil and natural gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile similar to the current market. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves, if there are differences in timing between the incurrence of significant costs of exploration or development activities and the recognition of significant proved reserves resulting from such activities and if we experience unsuccessful drilling activities. Expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period. Absent significant price increases, the sustained lower oil and natural gas prices experienced in the second half of 2014 and continuing throughout 2015 and 2016 continued to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn may make it more likely that we will incur impairment charges in the future against our oil and natural gas properties under full cost accounting.

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

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

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

- Selection of technology.

As of December 31, 2016, 68 gross (7.2 net) wells in which we have an interest were operated by other companies, representing 24% of our total gross wells (3.9% of our total net wells).

The indenture governing our Notes and the agreement governing our Term Loan impose significant operating and financial restrictions, which restrict us from incurring additional indebtedness and may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

The indenture governing our Notes and the documentation governing our Term Loan contain customary restrictions on our activities, including covenants that limit our and our subsidiaries' ability to:

- Transfer or sell assets or use asset sale proceeds;
- Incur or guarantee additional debt or issue preferred equity securities;

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

For more information, see Item 8. "Financial Statements and Supplementary Data, Note 4. Long-Term Debt."

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

Ares Management, L.P., which manages the affiliated funds that hold substantially all of our outstanding indebtedness and are also the largest beneficial owners of our common stock as of March 3, 2017, has the ability to influence our business plan significantly and may have interests that differ from our management and other shareholders.

On March 3, 2017, we refinanced all of our outstanding indebtedness with the issuance of a $250.0 million senior secured first lien five-year Term Loan and $125.0 million principal of five-year Notes issued to funds managed by affiliates of Ares Management, L.P. ("Ares"). In addition, Ares managed funds also acquired 29,408,305 shares of our common stock for $50.0 million cash, and as a result, became our largest stockholder with 15.8% of our outstanding common stock at March 3, 2017. See "Management's Discussion and Analysis of Financial Condition and Results of Operation – Liquidity and Capital Resources."

Ares also has the right to designate two directors to serve on our Board. The views of Ares as manager of our lenders, or any directors appointed by Ares, may differ from, or conflict with, the rest of our management on matters such as the need to raise capital or the need to waive or amend covenants in the Term Loan or the indenture governing the Notes in order to pursue our business plan or avoid a default under such agreements. In addition, Ares, through its affiliates managing our primary secured lenders, may take actions, or fail to grant waivers or amendments to agreements governing our indebtedness, that may not be consistent with, or may conflict with, the interests of other stockholders.

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

We use hedges to mitigate our oil and natural gas price risk with counterparties. If our counterparties fail or refuse to honor their obligations under these derivative instruments, our hedges of the related risk will be ineffective. This is a more pronounced risk to us in view of the recent stresses suffered by financial institutions. We cannot provide assurance that our counterparties will honor their obligations now or in the future. A counterparty's insolvency or inability or unwillingness to make payments required under terms of derivative instruments with us could have a material adverse effect on our financial condition and results of operations. At the date of filing of this Form 10-K, our counterparties were Morgan Stanley Capital Group Inc., Cargill, Incorporated, Koch Supply & Trading, LP and NextEra Energy Marketing, LLC.

Our significant net operating loss carry forwards that may be used to offset future U.S. federal income tax liabilities may become significantly limited in their use and value.

We have approximately $536.2 million of net operating loss carry forwards as of December 31, 2016, which are available to offset future U.S. federal income tax liabilities before they expire between 2030 and 2035. There is a significant risk that our ability to reduce potential future federal income tax liabilities utilizing net operating loss carry forwards would become substantially limited by reason of an "ownership change," as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the "Tax Code"). A company generally experiences such an ownership change if the percentage of its voting stock owned by its "5-percent shareholders," as defined in Section 382 of the Tax Code, increases by more than 50 percentage points over a rolling three-year "look-back" period. Such an ownership change could occur voluntarily if our board of directors decided it was in the best interest of the Company to issue a significant amount of its common stock, or involuntarily if one or more persons acquired 5% or more of the outstanding common stock of the Company or an existing significant holder of more than 5% of the outstanding common stock acquired more stock.

On January 27, 2017, we adopted a replacement stockholder rights plan (the "Rights Agreement") to effectively replace the stockholders rights plan adopted on January 18, 2016, which expired pursuant to its terms. Pursuant to the Rights Agreement, we declared a non-taxable dividend of one preferred share purchase right (each, a "Right") for each of the Company's issued and outstanding shares of common stock paid to stockholders of record on February 10, 2017. Each Right entitles the registered 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 $10.74, subject to certain adjustments. The Rights Agreement is designed to reduce the likelihood that the Company will experience an ownership change under Section 382 of the Tax Code by (i) discouraging any person or group from becoming a 4.95% shareholder of Company common stock and (ii) discouraging any existing 4.95% shareholder from acquiring additional shares of the Company's common stock. One or more persons could nevertheless acquire 5% of the outstanding common stock of the Company or increase their more than common stock ownership notwithstanding the Rights Agreement, or the Company could decide that its business plan required the issuance of common stock, which in either case could trigger an ownership change that would limit the use and value of the our net operating loss carry forwards to offset the payment of future U.S. federal income tax liabilities.

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

From time to time, we are subject to various significant legal proceedings and claims arising in the ordinary course of business. No assurance can be given regarding the outcome of these legal proceedings. Litigation, regardless of outcome or merit, however, can result in substantial costs and diversion of resources from our business. These costs would be reflected in terms of dollar outlay as well as the amount of time, attention and other resources that our management would have to appropriate to the defense of such claims. Considerable legal, accounting and other professional services expenses have been incurred in legal proceedings to date and significant expenditures may continue to be incurred in the future. Defense costs and any adverse outcome could adversely affect our business, financial condition and results of operations. For more information regarding our legal proceedings, see Item 8. "Financial Statements and Supplementary Data, Note 13. Commitments and Contingencies."

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

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

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

Our oil and natural gas exploration, development and production interest and operations are subject to stringent and complex federal, tribal, state, regional and local laws and regulations relating to the operation and maintenance of our facilities, including laws regulating removal of natural resources from the ground, the discharge of materials into the environment and otherwise relating to

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environmental protection. Oil and natural gas operations are also subject to federal, state, regional and local laws and regulations which seek to maintain occupational health and safety standards by regulating the design and use of drilling methods and equipment.

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

- Drilling and abandonment bonds or other financial responsibility assurances;
- Restriction on types, quantities and concentration of materials that may be released into the environment;
- Reports concerning operations;
- Spacing of wells;
- Limits or prohibitions on drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- The application of specific health and safety criteria addressing worker protection;
- The imposition of substantial liabilities for pollution resulting from our operations;
- Limitations on access to properties;
- Taxation; and
- Other regulatory controls on operating activities.

In addition, regulatory agencies have from time to time imposed price controls and limitations on production by restricting the flow rate of wells below actual production capacity in order to conserve supplies of oil and natural gas. Failure to comply with these laws and regulations applicable to our interests and operations could result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays or restrictions in permitting or the performance of projects, and the issuance of orders enjoining or limiting some or all of our operations in affected areas, any of which could have a material adverse effect on our financial condition. Legal requirements are sometimes unclear or subject to reinterpretation and may be amended in response to economic or political conditions. As a result, it is hard to predict the ultimate future cost of compliance with these requirements or their effect on our interests and operations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations may have a material adverse effect on our financial condition, future cash flows and the results of operations. For example, in October 2015, the EPA issued a final rule lowering the NAAQS for ozone to 70 parts per billion for both the 8-hour primary and secondary standards. States are expected to implement more stringent requirements as a result of this new final rule, which could apply to our operations. In a second example, in response to recent seismic events near belowground disposal wells used for the injection of oil and natural gas-related wastewaters, regulators in some states, including Oklahoma, have imposed more stringent permitting and operating requirements for produced water disposal wells. In Oklahoma, the OCC has implemented a variety of measures including adopting the National Academy of Science’s “traffic light system,” pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted and, further, evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors. Compliance with these or other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our expenditures and operating costs, which could adversely impact our business.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions or similar state agencies, but several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA published final CAA regulations in 2012 and again in June 2016 governing performance

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standards, including standards for the capture of air emissions released during hydraulic fracturing; ; published in June 2016 an effluent limited guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 establishing more stringent standards for performing hydraulic fracturing on federal and Indian lands, but, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government.

Also, from time to time the U.S. Congress considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma, where we operate, have adopted and other states are considering adopting legal requirements that could impose more stringent permitting, disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic activities in particular. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate or where we own working interests, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

We could incur significant costs and liabilities in responding to contamination that occurs as a result of our operations.

We may incur significant environmental costs and liabilities in the performance of our operations or in operations in which we own a working interest as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private parties, including the owners of properties upon which our wells or the wells in which we own a working interest are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in significant delays or restrictions in acquisition of permits or performance of projects, or more stringent or costly well drilling, construction, completion or water management activities, or waste, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

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

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

- Well blowouts, fires and explosions;
- Surface craterings and casing collapses;
- Road collapses;

- Uncontrollable flows of natural gas, oil, brine, water or well fluids;
- Pipe and cement failures;
- Formations with abnormal pressures;
- Stuck drilling and service tools;
- Pipeline or tank ruptures or spills;
- Natural disasters; and
- Environmental hazards, such as natural gas leaks, crude oil spills and unauthorized discharges of brine, toxic gases or well fluids.

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

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

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

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

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows.

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

The Federal Trade Commission, the FERC, and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

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

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that, in part, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

The CFTC has proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and trade-execution. Although we expect to qualify for the end-user exception to such requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for un-cleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts, materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter or reduce our ability to monetize or restructure our existing derivatives contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices.

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

Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

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

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has , however, adopted rules under authority of the CAA that, among other things, establish permitting reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting "best available control technology" standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations.

Federal agencies also have begun directly regulating emissions of methane from oil and natural gas operations. In June 2016, the EPA published Subpart OOOOa NSPS that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. Moreover, in November 2016, the EPA issued an ICR seeking information about methane emissions from facilities and operators in the oil and natural gas industry but on March 2, 2017, the EPA announced it was withdrawing the ICR so that the agency may further assess the need for the information that it was collecting through the request. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France in preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. The adoption and implementation of any international, federal or state legislation or regulations that require

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reporting of GHGs or otherwise limit emissions of GHGs from, our equipment and operations, or the equipment and operations of assets in which we own an interest, could require us to incur costs to reduce emissions of GHGs associated with those operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such physical effects were to occur, they could have an adverse effect on our exploration, development and production interests and operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

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

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

Technological changes could affect our operations.

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

We depend on our key personnel, the loss of which could adversely affect our operations and financial performance.

We depend, to a large extent, on the services of a limited number of senior management personnel and directors. Particularly, the loss of the services of our chief executive officer and chief financial officer could negatively impact our future operations. We have employment agreements with these key members of our senior management team; although, we do not maintain key-man life insurance on any of our senior management. We believe that our success is also dependent on our ability to continue to retain the services of skilled technical personnel. Our inability to retain skilled technical personnel could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Some of our directors may not be subject to suit in the United States.

Two of our six directors are citizens of Canada. As a result, it may be difficult or impossible to effect service of process within the United States upon those directors, to bring suit against them in the U.S. or to enforce in the U.S. courts any judgment obtained there against them predicated upon any civil liability provisions of the U.S. federal securities laws. Investors should not assume that Canadian courts will enforce judgments of U.S. courts obtained in actions against those directors predicated upon the civil liability provisions of the U.S. federal securities laws or the securities or “blue sky” laws of any state within the United States or will enforce, in original actions, liabilities against those directors upon the U.S. federal securities laws or any such state securities or blue sky laws.

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

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

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

The trading price of our common stock is subject to wide fluctuations in response to a variety of factors, including quarterly variations in operating results, announcements of drilling and rig activity, economic conditions in the natural gas and oil industry, general economic conditions or other events or factors that are beyond our control.

In addition, the stock market in general and the market for oil and natural gas exploration companies, in particular, have experienced large price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common stock regardless of our actual operating performance. In the past, following periods of volatility in the overall market and in the market price of a company's securities, securities class action litigation has been instituted against certain oil and natural gas exploration companies. If this type of litigation were instituted against us following a period of volatility in our common stock trading price, it could result in substantial costs and a diversion of our management's attention and resources, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Future issuances of our common stock may adversely affect the price of our common stock.

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

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

Our certificate of incorporation authorizes our board of directors to issue one or more series of preferred shares and set the terms of the preferred shares without seeking any further approval from our stockholders. The preferred shares that we have issued rank ahead of our common stock in terms of dividends and liquidation rights. We may issue additional preferred shares that rank ahead of our common stock in terms of dividends, liquidation rights or voting rights. If we issue additional preferred shares in the future, it may adversely affect the market price of our common stock. We have issued in the past, and may in the future continue to issue, in the open market at prevailing prices or in capital markets offerings series of perpetual preferred stock with dividend and liquidation preferences that rank ahead of our common stock.

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

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, the indenture under which the Notes were issued and the agreement governing the Term Loan contain covenants that significantly restrict the payment of cash dividends on our outstanding common stock and only limitedly permit the payment of cash dividends on our outstanding preferred stock as long as such debt remains outstanding. The payment of future dividends, if any, will be determined by our board of directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. Accordingly, stockholders must look solely to appreciation of our common stock to realize a gain on their investment, which may not occur.

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

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

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Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our properties consist primarily of oil and natural gas leases in the Mid-Continent area of the U.S. in Oklahoma.

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

Production, Prices and Operating Expenses

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

	For the Years Ended December 31,		
	2016	2015	2014
Production:			
Oil and condensate (MBbl)	1,105	1,425	975
Natural gas (MMcf)	6,145	13,759	11,598
NGLs (MBbl)	739	1,213	801
Total production (MBoe)	2,869	4,931	3,708
Daily Production:			
Oil and condensate (MBbl/d)	3.0	3.9	2.7
Natural gas (MMcf/d)	16.8	37.7	31.8
NGLs (MBbl/d)	2.0	3.3	2.2
Total daily production (MBoe/d)	7.8	13.5	10.2
Average sales price per unit[1]:			
Oil and condensate per Bbl, excluding impact of hedging activities	$38.92	$41.17	$84.98
Oil and condensate per Bbl, including impact of hedging activities[2]	$45.80	$46.86	$83.86
Natural gas per Mcf, excluding impact of hedging activities	$1.77	$1.23	$4.11
Natural gas per Mcf, including impact of hedging activities[2]	$2.04	$1.81	$3.84
NGLs per Bbl, excluding impact of hedging activities	$9.81	$5.89	$26.71
NGLs per Bbl, including impact of hedging activities[2]	$11.81	$14.42	$26.53
Average sales price per Boe, excluding impact of hedging activities	$21.30	$16.77	$40.95
Average sales price per Boe, including impact of hedging activities[2]	$25.06	$22.14	$39.78
Selected operating expenses (in thousands):			
Production taxes[3]	$1,908	$2,877	$6,733
Lease operating expenses[3]	$20,605	$23,728	$19,323

Transportation, treating and gathering[3]	$1,704	$2,187	$3,679
Depreciation, depletion and amortization	$29,673	$62,887	$46,180
Impairment of natural gas and oil properties	$48,497	$426,878	$—
General and administrative expense	$19,445	$17,069	$16,485
Selected operating expenses per Boe:			
Production taxes[3]	$0.67	$0.58	$1.82
Lease operating expenses[3]	$7.18	$4.81	$5.21
Transportation, treating and gathering[3]	$0.59	$0.44	$0.99
Depreciation, depletion and amortization	$10.34	$12.75	$12.45
General and administrative expense[4]	$6.78	$3.46	$4.45
Production costs[5]	$7.76	$4.98	$6.00

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

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

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

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

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

(4) General and administrative expenses include non-recurring costs related to acquisitions, allowance for bad debt, employee severance and corporate migration of $3.1 million, $1.4 million and $263,000 for the years ended December 31, 2016, 2015 and 2014, respectively. Excluding such costs, general and administrative expenses per Boe would have been $5.70, $3.18 and $4.37 for each respective year.

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

For the Year Ended
December 31, 2014

Selected operating expenses per Boe:		
Production costs	$	5.62

Drilling Activity

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

	For the Years Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	21.0	4.8	24.0	15.0	30.0	14.9
Non-productive	—	—	—	—	—	—
Total	21.0	4.8	24.0	15.0	30.0	14.9
Development wells:						
Productive	1.0	0.0	15.0	11.4	11.0	6.0
Non-productive	—	—	—	—	—	—
Total	1.0	0.0	15.0	11.4	11.0	6.0

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As of March 6, 2017, we were participating in nine gross (1.5 net) operated wells and one gross (0.3 net) non-operated well in the process of being drilled or completed in the Mid-Continent.

Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped and developed acreage in the areas indicated where we own a working interest as of December 31, 2016.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Appalachian Basin[1]	12,497	11,980	2,873	2,510
Mid-Continent	55,316	33,051	51,683	50,754
Total	67,813	45,031	54,556	53,264

(1) On January 20, 2017, we sold our remaining interest in producing wells and undeveloped acreage in West Virginia, effective January 1, 2017, for $200,000, before certain fees and expenses.

Undeveloped Acreage Expirations

The table below summarizes, by year as of December 31, 2016, our gross undeveloped acreage scheduled to expire, virtually all of which is located in our Mid-Continent area.

	Total Expiring Gross Acres	% of Total Undeveloped Gross Acres	
2017	29,314	43	%
2018	14,633	22	%
2019	11,038	16	%
2020	—	0	%
2021 and thereafter	—	0	%

The table below summarizes, by year as of December 31, 2016, our net undeveloped acreage scheduled to expire, virtually all of which is located in our Mid-Continent area.

	Total Expiring	% of Total Undeveloped Net Acres

	Net Acres		
2017	15,388	34	%
2018	8,995	20	%
2019	8,585	19	%
2020	5	0	%
2021 and thereafter	97	0	%

We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding three to five years. As is customary in the oil and natural gas industry, we can retain our interest in undeveloped acreage by commencing drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the primary term of such leases. We do not assign proved undeveloped reserves to leases after their expiration. In the Mid-Continent, approximately 1,700 net acres, or 11%, expiring during 2017 have automatic lease extension provisions allowing us to extend the lease for an additional two-year term by payment of lease bonus ranging from $450 to $1,000 per net acre. We plan to make the majority of the automatic lease extension payments. We also plan to extend the leases for any additional acreage expiring during 2017 in the Mid-Continent that do not have automatic lease extensions that we have determined to be in areas that are the focus of our future drilling operations. If we are not able to extend the lease, the acreage will expire. We may in the future, sell Mid-Continent acreage that we deem to be non-strategic. On January 20, 2017, we sold our remaining interest in producing wells and undeveloped acreage in West Virginia, effective January 1, 2017, for $200,000, before certain fees and expenses.

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Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2016. The term "gross" represents the total number of wells in which we own a working interest. The term "net" represents our proportionate working interest resulting from our ownership in gross wells. Productive wells are wells that are currently capable of producing oil or natural gas. Wells that are completed in more than one producing horizon are counted as one well.

	Productive Wells					
	Natural Gas		Oil		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin, West Virginia(1)	11.0	9.7	—	—	11.0	9.7
Mid-Continent, Oklahoma	170.0	102.6	48.0	35.6	218.0	138.2
Total	181.0	112.3	48.0	35.6	229.0	147.9

(1) On January 20, 2017, we sold our remaining interest in producing wells and undeveloped acreage in West Virginia, effective January 1, 2017, for $200,000, before certain fees and expenses. Subsequent to the closing of the transaction, we no longer own any productive natural gas wells in the Appalachian Basin.

Oil and Natural Gas Reserves

Reserve Estimation

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

Third Party Review of Reserves Estimates

For the years ended December 31, 2016, 2015 and 2014, reserves estimates for the Appalachian Basin and Mid-Continent area shown herein have been independently evaluated by Wright & Company, Inc. ("Wright"), a national firm providing petroleum property analysis for industry and financial organizations with extensive experience in both of our operating areas. Wright was founded in 1988 and performs consulting petroleum engineering services. A copy of Wright's summary reserve report is included as Exhibit 99.1 to this Form 10-K. Within Wright, the technical person primarily responsible for preparing the reserves estimates set forth in the Wright reserve report incorporated herein is Mr. D. Randall Wright. Mr. Wright has been practicing consulting petroleum engineering at Wright since 1988, the year in which he founded the company. He is a Registered Professional Engineer in the State of Texas and has over 40 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He has a Master of Science degree in Mechanical Engineering from Tennessee Technological University. The technical principal meets or exceeds the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimates

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

Since 2006, all of our reserves estimates have been reviewed and approved by our Senior Reservoir Engineer, who reports directly to our Chief Financial Officer. Our Senior Reservoir Engineer attended Texas A&M University and graduated in 1978 with a Bachelor of Science degree in Reservoir Engineering and has been involved in evaluations and the estimation of reserves and resources for over 30 years. During the year, our technical team may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operational conditions.

Technologies Used in Reserves Estimation

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

Estimated Proved Reserves

Our proved reserves information as of December 31, 2016 included in this Form 10-K was estimated by Wright using standard engineering and geosciences procedures and methods used in the petroleum industry. The technical personnel responsible for preparing the reserve estimates at Wright meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

In accordance with SEC regulations, estimates of our proved reserves and future net revenues as of December 31, 2016 were made using benchmark prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month price for natural gas and oil (“SEC pricing”). Key benchmark base prices utilized were the Henry Hub price of $2.48 per MMBtu for natural gas and a WTI spot oil price of $42.75 per barrel. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials. Estimated quantities of proved reserves and future net revenues are affected by oil and natural gas prices, which are highly volatile. Oil and natural gas prices have recently increased and the current 12-month unweighted arithmetic average of the first-day-of-the-month prices as of March 1, 2017 are 11% and 10%

higher than the SEC Pricing used as of December 31, 2016 for oil and natural gas, respectively. All of our proved reserves are located onshore within the U.S.

The following table summarizes our estimated proved reserves as of December 31, 2016:

	Total Proved Reserves			
	Producing	Non-producing	Undeveloped	Total
Oil and condensate (MBbls)	5,751	286	7,719	13,756
Natural gas (MMcf)	22,079	707	15,067	37,853
NGLs (MBbls)	3,060	121	2,331	5,512
Total proved reserves (MBoe)	12,491	524	12,562	25,577
PV-10 (in thousands)(1)	$100,838	$ 537	$ 39,956	$141,331
Standardized measure of discounted future net cash flows(1)				$141,331

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(1) PV-10 represents the present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. PV-10 is a non-U.S. GAAP financial measure because it excludes the effects of income taxes. We believe that PV-10 is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may use the measure as a basis for comparison of the relative size and value of our reserves to other companies. PV-10 should not be considered as an alternative to standardized measure of discounted future net cash flows as defined under U.S. GAAP. At December 31, 2016, we presently have approximately $536.2 million of net operating loss carryforwards, $50.7 million of foreign tax credit carryforwards and $276.5 million of remaining property tax basis for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, we will not incur future income taxes, and as such, the standardized measure of discounted future net cash flows is $141.3 million as of December 31, 2016.

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The following table summarizes our proved reserves by geographic area as of December 31, 2016:

SEC Pricing Case Proved Reserves[1]

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe	% Proved Developed	PV-10	Standardized Measure of Discounted Future Net Cash Flows
						(in thousands)	
Mid-Continent	13,756	37,773	5,512	25,564	51 %	$ 142,127	
Appalachian Basin, West Virginia[2]	—	80	—	13	100 %	(796)	
Total	13,756	37,853	5,512	25,577	51 %	$ 141,331	$ 141,331

(1) Key benchmark base prices utilized were the Henry Hub price of $2.48 per MMBtu for natural gas and a WTI spot oil price of $42.75 per barrel.
(2) On January 20, 2017, we sold our remaining interest in producing wells and undeveloped acreage in West Virginia, effective January 1, 2017, for $200,000, before certain fees and expenses.

Proved Undeveloped Reserves

As of December 31, 2016, our PUDs totaled 12.6 MMBoe all of which were associated with the Mid-Continent, representing a 54% decrease from our PUDs as of December 31, 2015. The December 31, 2016 PUDs consisted of 40 gross (34.0 net) wells in the Mid-Continent. The decrease in PUD reserves during 2016 is due to the removal of certain Hunton PUD locations as we now focus our capital activity on drilling Meramec and Osage wells to hold acreage by production and delineate our STACK Play position. The removal of certain PUD locations was the primary reason for the 16.2 MMBoe of downward revisions in 2016. We did not convert any year-end 2015 PUDs to proved developed reserves during 2016.

The following table summarizes our PUD activity during the year ended December 31, 2016:

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe
PUDs as of December 31, 2015	17,022	30,486	5,359	27,462

Extensions and discoveries	957	5,131	701	2,513
Purchases of reserves in place	—	—	—	—
PUDs converted to proved developed	—	—	—	—
Revisions of previous estimates	(10,260)	(20,550)	(3,729)	(17,413)
PUDs as of December 31, 2016	7,719	15,067	2,331	12,562

Estimated future development costs relating to the development of 2016 year-end PUDs is $111.7 million, of which 2017 and 2018 expenditures are $385,000 and $26.2 million, respectively, which includes the drilling of four gross (0.4 net) PUD locations in 2017 and eight gross (7.9 net) PUD locations in 2018. Under current SEC requirements, PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years of the original date of booking unless specific circumstances justify a longer time. All of our PUDs at December 31, 2016 are scheduled to be drilled by 2021, which is within five years from the date initially recorded as PUD reserves. We may be required to remove our PUD reserves if we do not drill those reserves within the required five-year time frame or if the PUD reserves do not remain economically producible under lower SEC prices. In addition, oil and natural gas prices sustained at current or lower levels and the resultant impact such prices may have on our drilling economics and our ability to raise capital could require us to re-evaluate and postpone our development drilling, which could result in the reduction or elimination of some of our proved undeveloped reserves.

Item 3. Legal Proceedings

Information about our legal proceedings is set forth in Item 8. “Financial Statements and Supplementary Data, Note 13, Commitments and Contingencies – Litigation” of this Form 10-K.

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Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock is traded on the NYSE MKT LLC under the symbol "GST." The following table sets forth the high and low sales prices of our common stock during the periods presented as reported by the NYSE MKT LLC.

	NYSE MKT LLC	
	High	Low
2016:		
Fourth quarter	$1.80	$0.82
Third quarter	$1.13	$0.80
Second quarter	$2.21	$0.83
First quarter	$1.38	$0.57
2015:		
Fourth quarter	$1.93	$1.00
Third quarter	$3.13	$1.00
Second quarter	$3.79	$2.58
First quarter	$3.27	$1.89

The last reported sale price of our common stock on the NYSE MKT LLC on March 6, 2017 was $1.83.

Stockholders

As of March 6, 2017, there were 248 stockholders of record who owned shares of our common stock.

Dividends

We have never declared or paid any cash dividends on our common stock. We anticipate that we will retain future earnings, if any, to satisfy our operational and other cash needs and do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the agreements governing our Notes and Term Loan prohibits us from paying cash dividends on our common stock as long as any debt remains outstanding.

For the year ended December 31, 2016, preferred stock cash dividends paid totaled $3.6 million. Effective March 9, 2016, the credit agreement governing our revolving bank credit facility (the "Revolving Credit Facility") was amended to, among other things, prohibit the payment of cash dividends on our preferred stock commencing April 2016. For the year ended December 31, 2016, there were $10.9 million of undeclared, unpaid cumulative preferred dividends. Pursuant to Amendment No. 10 to our Revolving Credit Facility, on January 10, 2017, we declared a special dividend on the Series A and Series B Preferred Stock to pay in full all accumulated and unpaid cash dividends accrued since April 1, 2016 at an annualized 8.62% and 10.75%, respectively, through the payment date of January 31, 2017. We paid the declared dividends for the period of April 2016 to January 2017 on January 31, 2017. Under Amendment No. 10, payment of the declared January 2017 dividend and monthly preferred stock cash dividends through March 2017 were permitted.

On March 3, 2017, our Revolving Credit Facility was fully repaid and terminated. Under the agreement governing the Term Loan and the indenture governing the Notes, cash dividend payments on our outstanding preferred stock are permitted through July 31, 2018 contingent upon the absence of any defaults. From and after August 1, 2018, dividend payments on the Series A Preferred Stock and Series B Preferred Stock are permitted subject to our compliance with a fixed charge coverage ratio test of not less than 1.0 to 1.0 from August 1, 2018, to, but excluding May 1, 2019 and of not less than 1.25 to 1.0 from and after May 1, 2019. If we fail to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then the fixed rate of Series A and Series B Preferred Stock each increases by 2.00% and the holders of such preferred stock, voting as a single class, will have the right to elect up to two directors to the board of directors of the Company.

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Issuer Purchases of Equity Securities

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

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans	(d) Maximum Number of Shares that May Yet be Purchased Under the Plan
November 1, 2016 - November 30, 2016	2,189	$ 1.05	—	n/a

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

Recent Sales of Unregistered Securities

We did not have any sales of unregistered securities during the year ended December 31, 2016.

Item 6. Selected Financial Data

The following table presents selected historical financial data as of and for the periods indicated. The selected consolidated financial data are derived from our audited consolidated financial statements. The following selected historical financial data should be read in connection with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

Financial information as of and for the year ended December 31, 2016 includes impairment of oil and natural gas properties of $48.5 million and a litigation settlement benefit of $10.1 million. Financial information as of and for the year ended December 31, 2015 includes impairment of oil and natural gas properties of $426.9 million. Financial information as of and for the year ended December 31, 2014 includes an $8.6 million net arbitration settlement benefit. Financial information as of and for the year ended December 31, 2013 includes a gain on acquisition of assets at fair value of $27.7 million. Financial information as of and for the year ended December 31, 2012 includes impairment of oil and natural gas properties of $150.8 million. Financial information as of and for the years ended December 31, 2013 and 2012 includes litigation settlement expense of $1.0 million and $1.3 million, respectively.

	As of and for the Years Ended December 31,				
	2016	2015	2014	2013	2012
	(in thousands, except per share data)				
Consolidated Statements of Operations:					
Revenues	$58,254	$107,294	$171,418	$87,755	$49,940

(Loss) income from operations	$(53,846)	$(428,834)	$78,512	$18,764	$(153,528)
Net (loss) income attributable to Common Stockholders	$(103,534)	$(473,980)	$36,529	$39,964	$(160,868)
Net (loss) income attributable to Common Stockholders per share:					
Basic	$(0.93)	$(6.11)	$0.58	$0.66	$(2.53)
Diluted	$(0.93)	$(6.11)	$0.55	$0.63	$(2.53)
Weighted average shares of common stock outstanding					
Basic	111,367	77,512	63,271	60,220	63,538
Diluted	111,367	77,512	66,493	63,618	63,538
Consolidated Balance Sheets:					
Property, plant and equipment, net	$192,004	$328,934	$692,300	$517,513	$256,251
Total assets	$300,204	$429,495	$775,794	$589,935	$290,068
Long-term liabilities	$410,905	$525,712	$370,480	$325,802	$106,020
Total stockholders' (deficit) equity	$(140,435)	$(120,185)	$350,286	$210,029	$126,536

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

You should read the following discussion of our historical performance, financial condition and future prospects in conjunction with the audited financial statements of Gastar Exploration Inc. and its subsidiaries as of the years ended December 31, 2016 and for the three years in the period ended December 31, 2016 together with the notes thereto included elsewhere in this Form 10-K.

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. 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 Meramec and Osage formations within the Mississippi Lime, the Oswego limestone, 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 in the Appalachian Basin Sale. We sold our remaining interest in producing wells and undeveloped leasehold in the Appalachian Basin on January 20, 2017 (effective January 1, 2017) for $200,000, before certain fees and expenses.

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

All of our current operational activities are conducted in the U.S. As of December 31, 2016, our major assets consist of approximately 107,000 gross (83,800 net) acres in the Mid-Continent area of the U.S. in the state of Oklahoma and approximately 15,400 gross (14,500 net) acres in the Appalachian Basin in West Virginia, all of which were sold on January 20, 2017. During the past three years, we spent approximately $466.8 million in property acquisitions, acreage, seismic, capitalized interest, drilling advances, reserve acquisition and exploratory and development drilling on this acreage. We last attained positive net income during 2014, but there can be no assurance that operating income and net earnings will be achieved in future periods. As we continue the exploitation and development drilling in the Mid-Continent, we expect to show improvement in our operating results.

On March 3, 2017, we refinanced all of our outstanding indebtedness with the issuance of a $250.0 million senior secured first lien Term Loan and $125.0 million principal of five-year Notes issued to funds managed by affiliates of Ares. In addition, Ares managed funds also acquired 29,408,305 shares of our common stock for $50.0 million cash. On such date, a portion of the net proceeds from these Ares transactions was used to repay all of our outstanding borrowings under our Revolving Credit Facility (which was terminated on such date), and the redemption price plus interest of all of our outstanding $325.0 million principal of 8 5/8% senior secured notes due 2018 (the "Former Notes") was funded to satisfy and discharge the Former Notes, which have been irrevocably called for redemption on March 24, 2017. See "- Liquidity and Capital Resources".

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

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

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

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

2016 Highlights

Mid-Continent STACK Play. At December 31, 2016, we held leases covering approximately 107,000 gross (83,800 net) acres in the Mid-Continent STACK Play, all of which we believe is prospective for one or several of the horizons comprising the STACK Play. During 2016, we completed seven gross (2.9 net) operated wells, including wells drilled and completed under the Development Agreement.

Mid-Continent Development Agreement. On October 14, 2016, we executed the Development Agreement to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma with an Investor in the Drilling Program which will target the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 32,900 gross (19,100 net) undeveloped net mineral acres under leases held by us. We will be the operator of all wells jointly developed under the Development Agreement. As of December 31, 2016, we had drilled and completed four gross (0.5 net) wells under the first tranche of the Development Agreement, all of which were on production.

At December 31, 2016, our proved reserves attributable to our Mid-Continent acreage were approximately 25.6 MMBoe. Mid-Continent proved reserves represented approximately 100% of our total proved reserves and our pre-tax PV-10 value at December 31, 2016. Oil, condensate and NGLs reserves comprised approximately 75% of the total Mid-Continent proved reserves and 51% of our total reserves were proved developed at year-end 2016.

Canadian County Property Sale. On October 19, 2016, we entered into a purchase and sale agreement for the South STACK Play Acreage Sale 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 and with a property sale effective date of August 1, 2016. On November 18, 2016, we executed and delivered two amendments to the sale agreement and entered into a relating closing agreement, which, among other things, allocated $1.4 million of the purchase price to producing properties with the remainder of the purchase price to non-producing properties. As of December 31, 2016, we had received approximately $48.6 million of the South STACK Play Acreage Sale proceeds. Subsequent to December 31, 2016, we have received an additional $9.5 million of South STACK Play Acreage Sale proceeds, which includes $5.0 million of the contingent payment. We anticipate receiving the remaining $12.7 million of South STACK Play Acreage Sale proceeds by July 2017, subject to certain adjustments.

Appalachian Basin Sale. On April 8, 2016, we completed the Appalachian Basin Sale and 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 the buyer. On January 20, 2017, we sold our remaining interests in producing wells and undeveloped acreage in the Appalachian Basin (effective January 1, 2017).

Financial Highlights

Our consolidated financial statements reflect total revenue of $58.3 million on total volumes of 2.9 MMBoe for the year ended December 31, 2016. Our operating loss for the year ended December 31, 2016 was $53.8 million and included impairment of oil and natural gas properties of $48.5 million, DD&A expense of $29.7 million and litigation settlement benefit of $10.1 million.

Results of Operations

The following is a comparative discussion of the results of operations for the periods indicated. It should be read in conjunction with the consolidated financial statements and the related notes to the consolidated financial statements, which are included in Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

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

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

	Year Ended December 31,		
	2016	2015	2014
	(In thousands, except per unit amounts)		
Revenues:			
Oil and condensate	$43,011	$58,668	$82,820
Natural gas	10,854	16,901	47,647
NGLs	7,252	7,136	21,382
(Loss) gain on commodity derivatives contracts	(2,863)	24,589	19,569
Total revenues	$58,254	$107,294	$171,418
Production:			
Oil and condensate (MBbl)	1,105	1,425	975
Natural gas (MMcf)	6,145	13,759	11,598
NGLs (MBbl)	739	1,213	801
Total production (MBoe)	2,869	4,931	3,708
Oil and condensate (MBbl/d)	3.0	3.9	2.7
Natural gas (MMcf/d)	16.8	37.7	31.8
NGLs (MBbl/d)	2.0	3.3	2.2
Total daily production (MBoe/d)	7.8	13.5	10.2
Average sales price per unit(1):			
Oil and condensate per Bbl, excluding impact of hedging activities	$38.92	$41.17	$84.98
Oil and condensate per Bbl, including impact of hedging activities(2)	$45.80	$46.86	$83.86
Natural gas per Mcf, excluding impact of hedging activities	$1.77	$1.23	$4.11
Natural gas per Mcf, including impact of hedging activities(2)	$2.04	$1.81	$3.84
NGLs per Bbl, excluding impact of hedging activities	$9.81	$5.89	$26.71
NGLs per Bbl, including impact of hedging activities(2)	$11.81	$14.42	$26.53
Average sales price per Boe, excluding impact of hedging activities	$21.31	$16.77	$40.95
Average sales price per Boe, including impact of hedging activities(2)	$25.06	$22.14	$39.78
Selected operating expenses (in thousands):			
Production taxes(3)	$1,908	$2,877	$6,733
Lease operating expenses(3)	$20,605	$23,728	$19,323
Transportation, treating and gathering(3)	$1,704	$2,187	$3,679
Depreciation, depletion and amortization	$29,673	$62,887	$46,180
Impairment of natural gas and oil properties	$48,497	$426,878	$—
General and administrative expenses(4)	$19,445	$17,069	$16,485
Selected operating expenses per Boe:			
Production taxes(3)	$0.67	$0.58	$1.82

Lease operating expenses(3)	$7.18	$4.81	$5.21
Transportation, treating and gathering(3)	$0.59	$0.44	$0.99
Depreciation, depletion and amortization	$10.34	$12.75	$12.45
General and administrative expenses(4)	$6.78	$3.46	$4.45
Production costs(5)	$7.76	$4.98	$6.00

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

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

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

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

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

(4) General and administrative expenses include non-recurring costs related to acquisitions, allowance for bad debt, employee severance costs and corporate migration of $3.1 million, $1.4 million and $263,000 for the years ended December 31, 2016, 2015 and 2014, respectively. Excluding such costs, general and administrative expenses per Boe would have been $5.70, $3.18 and $4.37 for each respective year.

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

For the Year Ended
December 31, 2014

Selected operating expenses per Boe:		
Production costs	$	5.62

Year Ended December 31, 2016 compared to Year Ended December 31, 2015

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $61.1 million for the year ended December 31, 2016, down 26% from $82.7 million for the year ended December 31, 2015. The decrease in revenues was the result of a 42% decrease in production partially offset by a 27% increase in weighted average realized prices. The decrease in production is the result of the Appalachian Basin Sale on April 8, 2016. 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 $11.0 million, or 16%, to $57.9 million for the year ended December 31, 2016 from the year ended December 31, 2015 as a result of a 17% decrease in weighted average realized equivalent prices for Mid-Continent production.

Average daily production on an equivalent basis was 7.8 MBoe/d for the year ended December 31, 2016 compared to 13.5 MBoe/d for the same period in 2015, of which Appalachian Basin production was 7.5 MBoe/d. For the years ended December 31, 2016 and 2015, production in the Mid-Continent averaged 6.0 MBoe/d. Total oil, condensate and NGLs production represented approximately 64% of our total production for the year ended December 31, 2016 compared to 53% of total production for the year ended December 31, 2015.

Oil and condensate revenues represented approximately 70% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2016 compared to 71% for the year ended December 31, 2015. Liquids revenues (oil, condensate and

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NGLs) represented approximately 82% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2016 compared to approximately 80% for the year ended December 31, 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 year ended December 31, 2016 compared to 79% for the year ended December 31, 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 year ended December 31, 2016 compared to 87% for the year ended December 31, 2015.

During the year ended December 31, 2016, we had commodity derivative contracts covering approximately 55% of our oil and condensate production. The impact of oil commodity derivative contracts settled during the year on oil and condensate sales was an increase in oil and condensate revenues of $7.6 million resulting in an increase in total price realized from $38.92 per Bbl to $45.80 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the year includes a loss of $480,000 for amortization of prepaid premiums and a loss of $2.5 million related to deferred put premiums. Excluding the non-cash amortization and deferred put premiums, the impact of hedging on oil and condensate sales was an increase in revenues of $10.5 million. During the year ended December 31, 2015, the impact of oil commodity derivative contracts settled during the year on oil and condensate sales was an increase of $8.1 million in oil and condensate revenues resulting in an increase in total price realized from $41.17 per Bbl to $46.86 per Bbl. The 2015 hedge impact included a loss of $43,000 of non-cash amortization of prepaid premiums and payment of deferred put premiums of $585,000. For the years ended December 31, 2016 and 2015, we designated 15% and 50%, respectively, our current crude hedges as price protection for our NGLs production.

During the year ended December 31, 2016, we had commodity derivative contracts covering approximately 49% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the year of $1.7 million and an increase in total price realized from $1.77 per Mcf to $2.04 per Mcf. The gain on commodity derivatives contracts settled during the year includes a loss of $225,000 for amortization of prepaid premiums and deferred put premiums. Excluding the non-cash amortization and deferred put premiums, the impact of hedging on natural gas sales was an increase in revenues of $3.6 million of NYMEX hedge gains offset by $1.7 million of basis losses. During the year ended December 31, 2015, the impact of natural gas commodity derivative contracts settled during the year on natural gas sales was an increase of $8.0 million in natural gas revenues resulting in an increase in total price realized from $1.23 per Mcf to $1.81 per Mcf. The 2015 hedge impact included a gain of $50,000 for amortization of prepaid premiums and deferred put premiums.

During the year ended December 31, 2016, we had commodity derivative hedge contracts covering approximately 40% of our NGLs production. The impact of hedging on NGLs sales during the year ended December 31, 2016 was an increase of $1.5 million in NGLs revenues resulting in an increase in total price realized from $9.81 per Bbl to $11.81 per Bbl. The NGLs commodity derivatives contracts settled during the year include a loss of $85,000 for amortization of prepaid premiums and a loss of $434,000 related to deferred put premiums. Excluding the non-cash amortization and deferred put premiums, the impact of hedging on NGLs sales was an increase in revenues of $2.0 million. During the year ended December 31, 2015, the impact of hedging contracts settled during the year for NGLs sales was an increase of $10.4 million in NGLs revenues resulting in an increase in total price realized from $5.89 per Bbl to $14.42 per Bbl. The 2015 hedge impact included a loss of $43,000 for non-cash amortization of prepaid premiums and payment of deferred put premiums of $585,000.

Losses related to the change in mark to market value for outstanding commodity derivatives contracts for the year ended December 31, 2016 were $13.6 million compared to losses of $1.9 million for the year ended December 31,

2015. The significant change in the mark to market value is primarily the result of higher future commodity prices and changes in hedge contracts during the period compared to the prior year.

Production taxes. We reported production taxes of approximately $1.9 million for the year ended December 31, 2016, down from $2.9 million for the year ended December 31, 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 increased $157,000, or 11%, to $1.6 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. As reported, production taxes for the years ended December 31, 2016 and 2015 were approximately 3.1% and 3.5%, respectively, of oil, condensate, natural gas and NGLs revenues. Excluding the Appalachian Basin, production taxes were approximately 2.8% and 2.1% of oil, condensate, natural gas and NGLs revenues for the years ended December 31, 2016 and 2015, respectively.

Lease operating expenses. We reported LOE of $20.6 million for the year ended December 31, 2016, down from $23.7 million for the year ended December 31, 2015. The decrease in LOE resulted from a $2.0 million decrease in workover expense, a $1.3 million decrease in ad valorem taxes due to the Appalachian Basin Sale and a $356,000 decrease in insurance costs offset by a $585,000 increase in controllable LOE costs from new wells. Our total LOE was $7.18 per Boe for the year ended December 31,

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2016, up 49% from $4.81 per Boe for the same period in 2015. Excluding the Appalachian Basin, LOE increased $434,000 to $19.7 million, or $8.96 per Boe, for the year ended December 31, 2016 from $19.3 million, or $8.85 per Boe, for the year ended December 31, 2015. The increase in Mid-Continent LOE from 2015 to 2016 resulted primarily from a $2.5 million increase in LOE for new wells and higher water disposal costs related to flush production offset by a $2.0 million decrease in workover activity. A summary of LOE by area is as follows:

	Lease Operating Expense For the Year Ended December 31, 2016		Lease Operating Expense For the Year Ended December 31, 2015		% Change of $ per Boe
	(in thousands)	($ per Boe)	(in thousands)	($ per Boe)	
Mid-Continent	$19,704	$8.96	$19,270	$8.85	1 %
Appalachian Basin(1)	901	$1.34	4,458	$1.62	(17)%
Total	$20,605	$7.18	$23,728	$4.81	49 %

(1) 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

Transportation, treating and gathering. We reported transportation expenses of $1.7 million for the year ended December 31, 2016, down from $2.2 million for the year ended December 31, 2015. Excluding the Appalachian Basin, transportation expense in the Mid-Continent increased $1.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 due to new wells and changes in Oklahoma marketing contracts from percent of proceeds to more fixed charges basis.

Depreciation, depletion and amortization. DD&A was $29.7 million for the year ended December 31, 2016, down from $62.9 million for the year ended December 31, 2015. The decrease in DD&A expense was the result of a 42% decrease in total production volumes resulting from the Appalachian Basin Sale on April 8, 2016 coupled with a 19% decrease in the DD&A rate per Boe. The DD&A rate for the year ended December 31, 2016 was $10.34 per Boe, as compared to $12.75 per Boe for the same period in 2015. The decrease in the DD&A rate per Boe 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 year ended December 31, 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. We reported ceiling impairments of $100.2 million, $182.0 million and $144.7 million, for the second, third and fourth quarters of 2015, respectively, resulting in total impairment of $426.9 million for the year ended December 31, 2015.

General and administrative expenses. We reported general and administrative expenses of approximately $19.4 million for the year ended December 31, 2016 compared to $17.1 million for the year ended December 31, 2015. Non-cash stock-based compensation expense, which is included in general and administrative expenses, was $3.9 million and $5.0 million for the years ended December 31, 2016 and 2015, respectively. Excluding stock-based compensation expense, general and administrative expense increased $3.4 million to $15.5 million for the year ended December 31, 2016 compared to $12.1 million for the year ended December 31, 2015. This increase is primarily due to $2.2 million of increased personnel costs including increased retention bonuses, severance costs for the Appalachian Basin employees and the retirement of the chief operating officer and approximately $2.0 million of bad debt expense related to the bankruptcy of a third-party purchaser of our production primarily in West Virginia partially offset by $600,000 of lower acquisition costs.

Litigation settlement benefit. We reported a litigation settlement benefit of $10.1 million for the year ended December 31, 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 years ended December 31, 2016 and 2015 were $455,000 and $488,000, respectively.

Interest expense. We reported interest expense of $35.2 million for the year ended December 31, 2016 compared to $30.7 million for the year ended December 31, 2015. Interest expense was reduced by $3.1 million and $3.9 million of capitalized interest in 2016 and 2015, respectively, which related to capital expenditures for undeveloped projects. Excluding capitalized interest, interest expense increased $3.8 million from December 31, 2015 to December 31, 2016 due to additional borrowings and higher grid pricing under our Revolving Credit Facility.

Dividends on Preferred Stock. Dividends on preferred stock totaled $14.5 million for the years ended December 31, 2016 and 2015, respectively. The dividends on preferred stock for the year ended December 31, 2016 include $10.9 million of accumulated unpaid and undeclared dividends for the period April through December 2016. The Series A Preferred Stock had a stated value and liquidation preference (excluding accumulated and unpaid dividends) of approximately $101.1 million at December 31, 2016 and 2015, respectively, and carries a cumulative dividend rate of 8.625% per annum. Total dividends on the Series A Preferred Stock were $8.7 million for the years ended December 31, 2016 and 2015, respectively. The 2016 dividends on the Series A Preferred Stock includes $6.5 million, or $1.61719 per share, of accumulated and unpaid dividends for the period April 2016 through December 2016. The Series B Preferred Stock had a stated value and liquidation preference (excluding accumulated and unpaid dividends) of $53.5 million at December 31, 2016 and 2015, respectively, and carries a cumulative dividend rate of 10.75% per annum. Total dividends on the Series B Preferred Stock were $5.8 million for the years ended December 31, 2016 and 2015, respectively. The 2016 dividends on the Series B Preferred Stock includes $4.3 million, or $2.0156256 per share, of accumulated and unpaid dividends for the period April through December 2016. Pursuant to Amendment No. 10 to our Revolving Credit Facility, on January 10, 2017, we declared a special cash dividend on the Series A Preferred Stock and Series B Preferred Stock to pay in full all accumulated and unpaid cash dividends accrued since April 1, 2016 at an annualized 8.625% and 10.75%, respectively, through the payment date of January 31, 2017.

Year Ended December 31, 2015 compared to Year Ended December 31, 2014

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) were $82.7 million for the year ended December 31, 2015, down 46% from $151.8 million for the year ended December 31, 2014. The decrease in revenues was the result of a 59% decrease in weighted average realized prices partially offset by a 33% increase in production. In addition to overall adverse commodity price conditions, we continued to be impacted by significant negative natural gas basis differentials in the Appalachian Basin and weakened NGLs pricing due to excess supply. Excluding the benefit of a one-time revenue adjustment of $10.6 million related to an arbitration settlement for the year ended December 31, 2014, weighted average Boe realized prices decreased 56% for the year ended December 31, 2015 compared to the year ended December 31, 2014.

Average daily production on an equivalent basis was 13.5 MBoe/d for the year ended December 31, 2015 compared to 10.2 MBoe/d for the same period in 2014. For the year ended December 31, 2015, production in the Mid-Continent averaged 6.0 MBoe/d compared to 2014 production of 4.4 MBoe/d, a 36% increase. The increase in Mid-Continent production is primarily due to additional production from 26 gross (21.6 net) wells brought online during 2015. For the year ended December 31, 2015, production in the Appalachian Basin averaged 7.5 MBoe/d compared to 2014 production of 5.8 MBoe/d, a 30% increase. The increase in Appalachian Basin production was due to seven gross (3.5 net) new Marcellus wells and one gross (0.5 net) Utica Shale well coming online coupled with full-year production from the Simms U-5H. Appalachian Basin production for the year ended December 31, 2015 includes 1.0 MBoe/d of Utica Shale production compared to 0.3 MBoe/d for the year ended December 31, 2014. Total oil, condensate and NGLs production represented approximately 53% of our total production for the year ended December 31, 2015 compared to 48% of total production for the year ended December 31, 2014.

Oil and condensate revenues represented approximately 71% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2015 compared to 55% for the year ended December 31, 2014. Liquids revenues (oil, condensate and NGLs) represented approximately 80% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2015 compared to approximately 69% for the year ended

December 31, 2014. Excluding a one-time adjustment related to an arbitration settlement, liquids revenues represented approximately 72% of our total oil, condensate, natural gas and NGLs revenues for the year ended December 31, 2014. Our average realized sales price per Boe in the Appalachian Basin, excluding the impact of hedging activities and the one-time adjustment related to an arbitration settlement in 2014, was $4.99 per Boe for the year ended December 31, 2015 compared to $22.87 per Boe for the year ended December 31, 2014.

During the year ended December 31, 2015, we had commodity derivative contracts covering approximately 34% of our oil and condensate production. The impact of oil commodity derivative contracts settled during the year on oil and condensate sales was an increase in oil and condensate revenues of $8.1 million resulting in an increase in total price realized from $41.17 per Bbl to $46.86 per Bbl. The gain on oil and condensate commodity derivatives contracts settled during the year includes a loss of $43,000 for amortization of prepaid premiums and a loss of $585,000 related to deferred put premiums. Excluding the non-cash amortization and deferred put premiums, the impact of hedging on oil and condensate sales was an increase in revenues of $8.7 million. During the year ended December 31, 2014, excluding the impact of a one-time revenue adjustment related to an arbitration settlement, the impact of hedging contracts settled during the year for oil and condensate sales was a decrease of $1.1 million in oil and condensate revenues resulting in a decrease in total price realized from $81.75 per Bbl to $80.63 per Bbl. The 2014 hedge impact included a loss of $36,000 of non-cash amortization of prepaid premiums and payment of deferred put premiums of $72,000. For both periods, we designated 50% of our current crude hedges as price protection for our NGLs production.

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During the year ended December 31, 2015, we had commodity derivative contracts covering approximately 65% of our natural gas production, which resulted in a gain on natural gas commodity derivatives contracts settled during the year of $8.0 million and an increase in total price realized from $1.23 per Mcf to $1.81 per Mcf. The gain on commodity derivatives contracts settled during the year includes a gain of $50,000 for amortization of prepaid premiums and deferred put premiums. Excluding the non-cash amortization and deferred put premiums, the impact of hedging on natural gas sales was an increase in revenues of $7.8 million of NYMEX hedge gains and $216,000 of basis gains. During the year ended December 31, 2014, the impact of hedging contracts settled during the year on natural gas sales was a decrease of $3.1 million in natural gas revenues resulting in a decrease in total price realized from $4.11 per Mcf to $3.84 per Mcf. The 2014 hedge impact included a loss of $317,000 for amortization of prepaid premiums. Excluding the impact of a one-time revenue adjustment related to an arbitration settlement during the year ended December 31, 2014, the total price realized for natural gas including the loss on natural gas commodity derivatives contracts settled during the year ended December 31, 2014 would have decreased from $3.41 per Mcf to $3.14 per Mcf.

During the year ended December 31, 2015, we had commodity derivative hedge contracts covering approximately 53% of our NGLs production. The impact of hedging on NGLs sales during the year ended December 31, 2015 was an increase of $10.4 million in NGLs revenues resulting in an increase in total price realized from $5.89 per Bbl to $14.42 per Bbl. The NGLs commodity derivatives contracts settled during the year include a loss of $43,000 for amortization of prepaid premiums and a loss of $585,000 related to deferred put premiums. Excluding the non-cash amortization and deferred put premiums, the impact of hedging on NGLs sales was an increase in revenues of $11.0 million. During the year ended December 31, 2014, excluding the impact of a one-time revenue adjustment related to an arbitration settlement, the impact of hedging contracts settled during the year for NGLs sales was a decrease of $143,000 in NGLs revenues resulting in a decrease in total price realized from $27.55 per Bbl to $27.37 per Bbl. The 2014 hedge impact included a loss of $36,000 for non-cash amortization of prepaid premiums and payment of deferred put premiums of $72,000.

Losses related to the change in mark to market value for outstanding commodity derivatives contracts for the year ended December 31, 2015 were $1.9 million compared to gains of $23.9 million for the year ended December 31, 2014. The significant change in the mark to market value is primarily the result of lower future commodity hedge prices and changes in hedge contracts during the period compared to the prior year.

Production taxes. We reported production taxes of approximately $2.9 million for the year ended December 31, 2015, down from $6.7 million for the year ended December 31, 2014. Production taxes for the year ended December 31, 2014 include $584,000 of additional production taxes attributed to a one-time revenue adjustment resulting from an arbitration settlement. Excluding the non-recurring adjustment, the decrease in production taxes primarily resulted from lower commodity prices related to our Marcellus Shale properties. Production taxes for the years ended December 31, 2015 and 2014 were approximately 3.5% and 4.4%, respectively, of oil, condensate, natural gas and NGLs revenues. The decrease in the production tax as a percentage of revenues is primarily the result of an increase in Mid-Continent revenues that benefit from an initial four-year production tax abatement reducing the rate from 7% to 1% on new horizontal wells drilled. Effective July 1, 2015, the production tax abatement on new horizontal wells drilled was reduced to an initial three-year production abatement period and the rate was reduced from 7% to 2%.

Lease operating expenses. We reported LOE of $23.7 million for the year ended December 31, 2015, up from $19.3 million for the year ended December 31, 2014. Our total LOE was $4.81 per Boe for the year ended December 31, 2015, down 8% from $5.21 per Boe for the same period in 2014. Excluding $185,000 of a one-time reduction to LOE related to an arbitration settlement, our total LOE would have been $5.26 per Boe for the year ended December 31, 2014. The increase in our LOE was primarily due to a $3.7 million increase in one-time workover expense for production enhancing workovers completed on certain WEHLU wells, a $597,000 increase in ad valorem taxes and a $547,000 increase in insurance costs partially offset by a $433,000 decrease in controllable LOE. Excluding workover expense, LOE per Boe for the year ended December 31, 2015 would have been $3.94 compared to $5.04 per Boe for the year ended December 31, 2014. A summary of LOE by area is as follows:

	Lease Operating Expense For the Year Ended December 31, 2015		Lease Operating Expense For the Year Ended December 31, 2014		% Change of $ per Boe
	(in thousands)	($ per Boe)	(in thousands)	($ per Boe)	
Mid-Continent	$19,270	$8.85	$15,112	$9.48	(7)%
Appalachian Basin	4,458	$1.62	4,211	$1.99	(19)%
Total	$23,728	$4.81	$19,323	$5.21	(8)%

The 7% and 19% decreases from December 31, 2014 to December 31, 2015 in LOE per Boe for the Mid-Continent and Appalachian Basin, respectively, is the result of increased production from new wells drilled.

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Transportation, treating and gathering. We reported transportation expenses of $2.2 million for the year ended December 31, 2015, down from $3.7 million for the year ended December 31, 2014. The year ended December 31, 2014 includes $1.6 million of expense attributed to a one-time adjustment related to an arbitration settlement. Excluding the one-time adjustment, transportation expense for the year ended December 31, 2014 would have been $2.1 million.

Depreciation, depletion and amortization. DD&A was $62.9 million for the year ended December 31, 2015, up from $46.2 million for the year ended December 31, 2014. The increase in DD&A expense was the result of a 33% increase in total production volumes coupled with a 2% increase in the DD&A rate per Boe. The DD&A rate for the year ended December 31, 2015 was $12.75 per Boe, as compared to $12.45 per Boe for the same period in 2014. The increase in the DD&A rate per Boe is primarily due to higher cost liquids-focused drilling resulting in an increase in our total liquids production as a percentage of total production for the year ended December 31, 2015 compared to the year ended December 31, 2014 and the additional allocation of $14.4 million of undeveloped Marcellus acreage costs from unproved to proved properties based on reduced drilling activity. Liquids production represented approximately 53% of total production for the year ended December 31, 2015 compared to 48% of total production for the year ended December 31, 2014.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $426.9 million for the year ended December 31, 2015. The impairment was the result of a 40% decline in the 12-month average natural gas price and a 47% decline in the 12-month average oil price used in the calculation of our full cost ceiling test at December 31, 2015 compared to December 31, 2014. At December 31, 2015, our ceiling test impairment calculation was based on SEC pricing of $2.59 per MMBtu of Henry Hub spot natural gas and $50.28 per barrel of West Texas Intermediate spot oil.

General and administrative expenses. We reported general and administrative expenses of approximately $17.1 million for the year ended December 31, 2015 compared to $16.5 million for the year ended December 31, 2014. Non-cash stock-based compensation expense, which is included in general and administrative expenses, was $5.0 million and $4.9 million for the years ended December 31, 2015 and 2014, respectively. Excluding stock-based compensation expense, general and administrative expense increased $493,000 to $12.1 million for the year ended December 31, 2015 compared to $11.6 million for the year ended December 31, 2014. This increase is primarily due to acquisition costs of $1.1 million and employee severance costs of $310,000 partially offset by lower bonus expense.

Interest expense. We reported interest expense of $30.7 million for the year ended December 31, 2015 compared to $27.6 million for the year ended December 31, 2014. Interest expense is reduced by $3.9 million and $4.3 million of capitalized interest in 2015 and 2014, respectively, which related to capital expenditures for undeveloped projects in the Appalachian Basin and the Mid-Continent. Excluding capitalized interest, interest expense increased $2.6 million from December 31, 2014 to December 31, 2015 due to higher outstanding debt balances under the Revolving Credit Facility.

Dividends on Preferred Stock. We reported dividends on preferred stock of $14.5 million and $14.4 million for the years ended December 31, 2015 and 2014, respectively. The Series A Preferred Stock had a stated value and liquidation preference of approximately $101.1 million at December 31, 2015 and 2014, respectively, and carries a cumulative dividend rate of 8.625% per annum. Dividends on the Series A Preferred Stock were $8.7 million for the years ended December 31, 2015 and 2014, respectively. The Series B Preferred Stock, issued during November 2013, had a stated value and liquidation preference of $53.5 million at December 31, 2015 and 2014, respectively, and carries a cumulative dividend rate of 10.75% per annum. Dividends on the Series B Preferred Stock were $5.8 million for the years ended December 31, 2015 and 2014.

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 acceptable terms. We believe that our current cash position and funds from operating cash flows should be sufficient to meet our cash requirements for 2017 and early 2018. 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. Current market conditions may put limitations on our ability to issue new debt or equity securities in the public or private markets.

For the year ended December 31, 2016, we reported cash flows provided by operating activities of $6.7 million. We reported net cash provided by investing activities of $66.5 million for the year ended December 31, 2016, primarily from $121.3 million of proceeds from the sale of oil and natural gas properties partially offset by $59.9 million for the development of oil and natural gas properties. For the year ended December 31, 2016, we reported net cash used in financing activities of $51.8 million, consisting primarily of $115.4 million of repayments on the Revolving Credit Facility partially offset by $69.2 million of net proceeds from the issuance of common shares. As a result of these activities, our cash and cash equivalents balance increased by $21.5 million, resulting in a December 31, 2016 balance of cash and cash equivalents of $71.5 million. Net cash provided by operating activities decreased $44.5 million from 2015 primarily due to lower oil, condensate, natural gas and NGLs revenues in 2016 resulting from the Appalachian Basin Sale. Cash flow from investing activities increased $216.9 million from 2015 to 2016 primarily due to proceeds received from the Appalachian Basin Sale and the South STACK Play Acreage Sale coupled with decreased drilling and acquisition activity.

At December 31, 2016, we had a net working capital surplus of approximately $75.6 million. At December 31, 2016, we had no availability under the Revolving Credit Facility which had a borrowing base of $85.0 million under which there were $84.6 million of borrowings outstanding and $370,000 of letters of credit issued. On January 9, 2017, in connection with Amendment No. 9 to the Revolving Credit Facility, we made a payment of $457,000 toward our outstanding balance with no impact on the borrowing base. On January 31, 2017, in accordance with Amendment No. 10 to the Revolving Credit Facility, we paid down our outstanding balance under the Revolving Credit Facility in the amount of $12.1 million, equal to the January 2017 preferred dividend payment and our borrowing base was reduced to $72.9 million. On February 2, 2017, we made an additional payment of $1.7 million as required by Amendment No. 10 and our borrowing base was reduced from $72.9 million to $71.3 million. On February 9, 2017, the outstanding letter of credit in the amount of $370,000 was cancelled.

On March 3, 2017, pursuant to a Securities Purchase Agreement dated February 16, 2017 (as amended, the "Purchase Agreement") with certain funds (the "Purchasers") managed by affiliates of Ares, pursuant to which we issued and sold for cash to the Purchasers (i) the Notes ($125.0 million aggregate principal amount) sold at par, which Notes, subject to the receipt of approval of our stockholders, will be convertible into our common stock or, in certain circumstances, cash in lieu of common stock or a combination thereof as described below and (ii) 29,408,305 shares of common stock for a cash purchase price of $50.0 million. In addition, affiliates of Ares concurrently loaned us $250.0 million pursuant to a senior secured first-lien Term Loan. On such date, a portion of the net proceeds from these Ares transactions was used to repay all of our outstanding borrowings under our Revolving Credit Facility (which was terminated on such date), and the redemption price plus interest of all of our outstanding $325.0 million principal of the Former Notes was funded to satisfy and discharge the Former Notes, which have been irrevocably called for redemption on March 24, 2017.

As of March 6, 2017, our cash balance was $42.6 million and we had $250.0 million of first-lien Term loan borrowings and $125.0 million of second-lien secured 6.0% convertible notes outstanding, both with a maturity of March 2022.

Future capital and other expenditure requirements. Our preliminary capital budget for 2017 is approximately $84.0 million, which contemplates approximately $39.2 million for STACK Play operated drilling and completion activity, $3.3 million for recompletion projects on producing operated Oklahoma wells, $3.5 million for our participation in non-operated STACK Play drilling, $30.8 million for leasehold costs and $7.2 million for capitalized interest and administration costs. We plan to fund our 2017 capital budget through existing cash balances, recent financing activities and internally generated cash flow from operating activities. 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 access to additional capital. We operate approximately 95% of our budgeted 2017 capital expenditures, and thus, we could reduce a significant portion of 2017 capital expenditures if necessary to better match available capital resources. For more information, see Item 1A. "Risk Factors-Our development operations will require substantial capital expenditures in order to grow or maintain our production levels. Our limited access to the funds for necessary future growth and maintenance capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay cash dividends to our preferred stockholders and to make required payments on our indebtedness."

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. Historically, we designated 50% of our current crude oil hedges as price protection for a portion of our NGLs production. Commencing in 2016, we began designating 15% of our crude oil hedges as price protection for a portion of our NGLs production to better match NGLs production subsequent to the sale of our Appalachian Basin assets.

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As of March 6, 2017, the following crude derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume (1)	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
		(in Bbls)					
March to December 2017	Costless three-way collar	280	85,680	$—	$80.00	$65.00	$97.25
March to September 2017	Costless three-way collar	250	53,500	$—	$80.00	$60.00	$98.70
October 2017	Costless three-way collar	200	6,200	$—	$80.00	$60.00	$98.70
November 2017	Costless three-way collar	250	7,500	$—	$80.00	$60.00	$98.70
December 2017	Costless three-way collar	200	6,200	$—	$80.00	$60.00	$98.70
March to December 2017	Put spread	500	153,000	$—	$82.00	$62.00	$—
March 2017	Fixed price swap	1,175	36,425	$—	$—	$—	$—
April to June 2017	Fixed price swap	975	88,725	$—	$—	$—	$—
July to December 2017	Fixed price swap	400	73,600	$54.50	$—	$—	$—
January to August 2018	Put Spread	425	103,275	$54.50	$—	$—	$—
January to December 2018	Costless three-way collar	500	182,500	$54.50	$—	$—	$—

(1) Crude volumes hedged include oil, condensate and certain components of the Company's NGLs production.

As of March 6, 2017, the following natural gas derivative transactions were outstanding with the associated notional volumes and weighted average underlying hedge prices:

Settlement Period	Derivative Instrument	Average Daily Volume	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
		(in MMBtu's)					
April to December 2017	Costless three-way collar	5,000	1,375,000	$ —	$ 3.00	$2.35	$ 4.00
January to December 2018	Costless three-way collar	5,000	1,825,000	$ —	$ 3.00	$2.35	$ 4.00

For more information, see Item 8. "Financial Statements and Supplementary Data, Note 7. Derivative Instruments and Hedging Activity" included in this Form 10-K.

At December 31, 2016, the estimated fair value of all of our commodity derivative instruments was a net asset of $7.5 million, comprised of current and non-current assets and liabilities. In conjunction with certain derivative hedging activity, we deferred the payment of certain put premiums for the production month period January 2017 through December 2018. At December 31, 2016, we had a current commodity derivative premium payable of $1.7 million and a long-term commodity derivative premium payable of $969,000. The put premium liabilities are payable monthly as the hedge production month becomes the prompt production month.

By removing the price volatility from a portion of our oil, condensate, natural gas and NGLs sales for 2017 and 2018, we believe that we have mitigated, but not eliminated, the potential effects of changing prices on a portion of our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, derivative contracts can limit the benefits we could receive from increases in commodity prices. For additional information on the impact of changing commodity prices on our financial position, see Item 7A. “Quantitative and Qualitative Disclosure about Market Risk.” As of December 31, 2016, all of our economic derivative hedge positions were with a multinational energy company or large financial institutions, which are not known to us to be in default on their derivative positions. Credit support for the majority of our open derivatives at December 31, 2016 was provided under the Revolving Credit Facility. Although we are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above, we do not anticipate non-performance by such counterparties. In conjunction with the Ares transactions and the pay off and termination of our Revolving Credit Facility on March 3, 2017, our economic derivative hedge positions were novated and are currently with a large financial institution and certain large companies engaged in the derivative hedging business, none of which are known to us to be in default on their derivative positions.

ATM Program. We previously had an at-the-market equity offering program (the “ATM Program”) pursuant to which we could 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 determined from time to time. Actual issuances depended 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. During the year ended December 31, 2016, we issued 18,606,943 shares of common stock under the ATM Program for net proceeds of $24.4 million. For the period January 1, 2017 to January 20, 2017, we issued an

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additional 5,447,919 shares of common stock under the ATM Program for net proceeds of $8.3 million. The ATM Program expired on February 24, 2017 and we can no longer issue and sell additional shares of common stock under the ATM Program.

Term Loan Facility. On March 3, 2017, the Company entered into a Third Amended and Restated Credit Agreement among the Company, as borrower, the guarantors party thereto, funds managed by affiliates of Ares, as lenders, and Wilmington Trust, National Association, as Administrative Agent, a $250.0 million term loan (the "Term Loan"). The Term Loan was issued at par and bears interest at a per annum rate equal to 8.5%, payable on a quarterly basis on each March 1, June 1, September 1 and December 1 of each year, commencing June 1, 2017, and has a scheduled maturity of March 3, 2022. In addition, the Term Loan is subject to an interest "make-whole" and repayment premium, such that any repayment or prepayment of the loans thereunder prior to the stated maturity date shall be subject to the payment of a repayment premium, and depending on the date of such repayment or prepayment, the applicable interest "make-whole" amount, with the amount of such repayment premium decreasing over the life of the Term Loan.

The Term Loan is secured by a first-priority lien on substantially all of the assets of the Company and its subsidiaries, excluding certain assets as customary exceptions.

The Term Loan contains various customary covenants for credit facilities of this type, including, among others, restrictions on granting liens, incurrence of other indebtedness, payments of certain dividends and other restricted payments, engaging in transactions with affiliates, dispositions of assets and other, in each case subject to certain baskets and exceptions;

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

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

Revolving Credit Facility. On March 3, 2017, we used a portion of the net proceeds from the Ares transactions described above to fully repay the $69.2 million of outstanding borrowings under our Revolving Credit Facility and terminate the facility.

Senior Secured Notes. On March 3, 2017, we used a portion of the net proceeds from the Ares transactions described above to satisfy and discharge the $325.0 million of our outstanding Former Notes, including $7.0 million of prepayment penalty and $10.0 million of accrued interest.

Notes. On March 3, 2017, we issued for cash at par $125.0 million principal amount of the Notes under an indenture (the "Indenture") by and among the Company, the subsidiary guarantor named therein, and Wilmington Trust, National Association, as trustee (the "Trustee") and collateral trustee. The Notes bear interest initially at 6.0% per annum and will mature on March 1, 2022, unless earlier repurchased, redeemed or converted in accordance with the terms of the Indenture prior to such date. Interest is payable on the Notes on each March 1, June 1, September 1 and December 1 of each year, commencing June 1, 2017.

If holders of issued and outstanding common stock (other than shares recently issued to funds managed by affiliates of Ares) approve the conversion rights of the Notes on or before July 3, 2017 in a manner satisfactory to meet the requirements of The NYSE MKT (the "Requisite Stockholder Approval"), the Notes will become convertible at the option of the holder into shares of common stock based on an initial conversion price of $2.2103 per share, subject to certain adjustments and the issuance of additional "make-whole" shares under certain circumstances specified in the Indenture. Subject to certain limitations, the Company will have the right to settle its conversion obligations on the Notes in common stock, or in cash or a combination thereof. If the Company obtains the Requisite Stockholder Approval, then the Company will have the right to redeem the Notes (i) on or after March 3, 2019 if the common stock trades above 150% of the conversion price for periods specified in the Indenture; and (ii) on or after March 1, 2021 without regard to such condition, in each case at par plus accrued interest.

If the Requisite Stockholder Approval is not obtained on or before July 3, 2017, the Notes will not be convertible and the interest rate payable on the Notes will increase in increments to 15.0% per annum, and will not be redeemable by the Company prior to maturity except upon payment of a "make-whole" redemption premium. The interest rate on the Notes will also be subject to an increase in certain circumstances if the Company fails to comply with certain obligations under the Registration Rights Agreement (as defined below), or in the case of certain issuances of common stock at below the initial reference price of $1.7002 per share.

The Notes are secured by a second-priority lien on substantially all of the assets of the Company. The Indenture restricts the ability of the Company and certain of its subsidiaries to, among other things: (i) pay dividends or make other distributions in respect

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of the Company's capital stock or make other restricted payments; (ii) incur additional indebtedness and issue preferred stock; (iii) make certain dispositions and transfers of assets; (iv) engage in transactions with affiliates; (v) create liens; (vi) engage in certain business activities that are not related to oil and gas; and (vii) impair any security interest. These covenants are subject to a number of exceptions and qualifications.

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. 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 on the Series A Preferred Stock have and will continue to accumulate regardless of whether any such dividends are declared or not. Accumulated and unpaid dividends for the period April 2016 through December 2016 totaled $6.5 million, or $1.6171875 per share, at December 31, 2016. For the year ended December 31, 2016, we recognized total dividends of $8.7 million for the Series A Preferred Stock.

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. 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 on the Series A Preferred Stock have and will continue to accumulate regardless of whether any such dividends are declared or not. Accumulated and unpaid dividends for the period April 2016 through December 2016 totaled of $4.3 million, or $2.0156256 per share, at December 31, 2016. For the year ended December 31, 2016, we recognized total dividends of $5.8 million for the Series B Preferred Stock.

Pursuant to Amendment No. 10 to our Revolving Credit Facility, on January 10, 2017, we declared a special cash dividend on the Series A Preferred Stock and Series B Preferred Stock to pay in full all accumulated and unpaid cash dividends accrued since April 1, 2016 at an annualized 8.625% and 10.75%, respectively, through the payment date of January 31, 2017. Under Amendment No. 10 to the Revolving Credit Facility, payment of the declared Series B Preferred Stock January 2017 dividend and monthly preferred stock cash dividends through May 2017 were permitted. Under the agreement governing the Term Loan and the indenture governing the Notes, cash dividend payments are permitted through July 31, 2018 contingent upon the absence of any defaults. From and after August 1, 2018, dividend payments on the outstanding Series A and Series B Preferred Stock are permitted subject to the further condition that we are in compliance with a fixed charge coverage ratio of not less than 1.0 to 1.0 from August 1, 2018, to, but excluding May 1, 2019 and of not less than 1.25 to 1.0 from and after May 1, 2019. Dividends on the Series A and Series B Preferred Stock will accumulate regardless of whether any such dividends are declared. The Series A Preferred Stock dividend is a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference, or $2.15625 per share outstanding each year, and on the Series B Preferred Stock a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference, or $2.6875 per share outstanding each year. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then the fixed rate of Series A and Series B Preferred Stock each increases by 2.00% and the holders, voting as a single class, will have the right to elect up to two directors to our board of directors.

Off-Balance Sheet Arrangements

As of December 31, 2016, we had no off-balance sheet arrangements. We have no plans to enter into any off balance sheet arrangements in the foreseeable future.

Contractual Obligations

The following table summarizes our future contractual obligations as of December 31, 2016:

	Payments Due by Period						
	Total	2017	2018	2019	2020	2021	Thereafter
	(in thousands)						
Long-term debt(1)	$409,630	$84,630	$325,000	$—	$—	$—	$ —
Interest on long-term debt(2)	42,034	31,560	10,474	—	—	—	—
Deferred put premiums(3)	2,623	1,654	969	—	—	—	—
Office space leases(4)	3,195	418	718	609	617	624	209
Office equipment leases	55	29	15	8	3	—	—
Total contractual obligations	$457,537	$118,291	$337,176	$617	$620	$—	$ —

(1) For a discussion of the Revolving Credit Facility and the Notes, see Item 8. “Financial Statements and Supplementary Data, Note 4. Long-Term Debt” included in this Form 10-K. As a result of the Ares transactions described above, on March 3, 2017,

our Revolving Credit Facility was paid in full and terminated and the $325.0 million principal of outstanding Former Notes was satisfied and discharged. Additionally, on March 3, 2017, we entered into a five-year $250.0 million first lien secured Term Loan and issued $125.0 million of Notes due 2022.

(2) Interest payments have been calculated by applying the weighted average interest rate of 8.625% at December 31, 2016 to the outstanding Notes balance of $325.0 million at December 31, 2016 and by applying the weighted average interest rate of 4.78% at December 31, 2016 to the outstanding Revolving Credit Facility balance of $84.6 million at December 31, 2016.

(3) In conjunction with certain crude commodity derivatives contracts, we deferred the payment of certain put premiums for the period January 2017 to December 2018. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

(4) Our Houston office lease obligation expires April 30, 2022 and our Oklahoma office lease expires on October 31, 2018.

We maintain a liability for costs associated with the retirement of tangible long-lived assets. At December 31, 2016, our reserve for these obligations totaled $5.5 million for which no contractual commitment exists. Upon closing of the sale of our remaining assets in the Appalachian Basin during the first quarter of 2017, we will reduce our asset retirement obligations by approximately $919,000. Information about this liability is set forth in Item 8. “Financial Statements and Supplementary Data, Note 2. Summary of Significant Accounting Policies – Asset Retirement Obligation” included in this Form 10-K.

We have employment agreements with our Chief Executive Officer and Chief Financial Officer which obligate us to pay a specified level of salary, target bonus and certain other payments and reimbursements to them during their employment and in the event of termination or change of control. The employment agreement with our Chief Operating Officer terminated upon his retirement on February 1, 2016. Information about such payments is set forth in Item 11. “Executive Compensation” of this Form 10-K.

Commitments

Gas Purchase Agreement

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI with respect to our Marshall County, West Virginia production. The initial term of the gas purchase agreement was five years with the option to extend the term of the gas purchase agreement for an additional five year period. Our Marshall County, West Virginia production was dedicated to SEI for the term of the gas purchase agreement and SEI would purchase all hydrocarbon production. During June 2014, we entered into an agreement to include the dedication of all of our Wetzel County, West Virginia production to SEI in addition to our Marshall County, West Virginia production. Upon closing of the Appalachian Basin Sale, we no longer utilize SEI and have no further obligations under the SEI agreement. On June 3, 2016, SEI filed for Chapter 7 bankruptcy and we determined that a receivable from SEI would no longer be collectible.

Drilling Program

On October 14, 2016, we entered into the Development Agreement with the Investor for the proposed Drilling Program. Upon completion of a Drilling Program tranche, the Investor has the right, but not the obligation, for a period of six months to cause us to purchase their WI Tail interest for such tranche for fair market value by applying the methodology to determine a 15% discounted present value as defined by the Development Agreement. If the Investor fails to exercise the Investor Put Right within the six-month period after achieving final reversion, then for a period of six months thereafter, we shall have the right, but not the obligation, to purchase the WI Tail from the

Investor on the same fair market value approach of the Investor Put Right. If final reversion has not been achieved by the eighth anniversary of the spud date of the first well in a given tranche, Investor will, for a period of six months thereafter, have the right to cause us to buy Investor's then-current interest in such tranche at an agreed upon valuation.

Critical Accounting Policies and Estimates

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

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expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate or policy to be critical if:

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

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

Full Cost Method of Accounting

We follow the full cost method of accounting for oil and natural gas operations, whereby all costs incurred in the acquisition, exploration and development of oil and natural gas reserves are initially capitalized into cost centers on a country-by-country basis whether or not the activities to which they apply are successful. Currently, our only cost center is the U.S. These costs include land acquisition costs attributable to proved reserves, geological and geophysical expenditures, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition, exploration and development activities. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that directly relate to our natural gas and oil activities. Interest costs related to unproved properties are also capitalized. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our natural gas and oil properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves, as determined by independent petroleum engineers. The percentage of total reserve volumes produced during the year is multiplied by the net capitalized investment plus future estimated development costs in those reserves to determine depletion expense for the period.

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

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

Full Cost Ceiling Limitation

The full cost method of accounting for oil and natural gas properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full cost ceiling calculation. The ceiling is the present value of estimated future cash flow from proved oil and natural gas reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage) to the extent not included in oil and natural gas properties pursuant to authoritative guidance and estimated future income taxes thereon. To the extent that our capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling, the excess must be written off to expense. Once incurred, this impairment of oil and natural gas properties is not reversible at a later date even if oil and natural gas prices increase.

The ceiling calculation dictates that the 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect are held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on historical average prices and costs in effect at the time of the evaluation. If the net cost exceeds the ceiling, an impairment loss is recognized for the amount by which the net cost exceeds the ceiling and is shown as a reduction in oil and natural gas properties and as additional depletion. Proceeds from a sale of oil and natural gas properties will be applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion or amortization.

In applying the full cost method of accounting, we perform a ceiling test at each reporting period on the cost center properties whereby the net cost of oil and natural gas properties, net of related deferred income taxes ("net cost"), is limited to the sum of the estimated future net revenues from our proved reserves using the 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas held constant, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects. The tables below set forth relevant pricing assumptions utilized in the quarterly ceiling test

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computations, before adjustment for basis and quality differentials, and the associated impairments recorded for the respective periods noted.

	2016				
	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$ 2.48	$ 2.28	$2.24	$2.40
West Texas Intermediate oil price (per Bbl)(1)		$ 42.75	$ 41.68	$43.12	$46.26
Impairment recorded (pre-tax) (in thousands)	$48,497	$ —	$ —	$—	$48,497

	2015				
	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)(1)		$2.59	$3.06	$3.39	$3.88
West Texas Intermediate oil price (per Bbl)(1)		$50.28	$59.21	$71.68	$82.72
Impairment recorded (pre-tax) (in thousands)	$426,878	$144,760	$181,966	$100,152	$—

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

The most likely factor to contribute to a ceiling test impairment is the price used to calculate the reserve limitation threshold. A significant reduction in the prices at a future measurement date could trigger a full cost ceiling impairment. A 10% decrease in prices at December 31, 2016 would have resulted in a ceiling impairment of approximately $16.1 million. A 10% increase in prices at December 31, 2016 would have increased our ceiling impairment cushion by approximately $38.3 million.

Oil and Natural Gas Reserves

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

In addition, economically producible reserves are dependent on the oil and natural gas prices used in the reserves estimate. We based our December 31, 2016 reserves estimates on a 12-month unweighted average of the first-day-of-the month prices, in accordance with SEC rules. However, oil and natural gas prices are volatile and, as a result, our reserves estimates will change in the future. Despite the inherent imprecision in these engineering estimates, our proved reserve volumes and values are used to calculate depletion and impairment provisions.

Depreciation, Depletion and Amortization

The units-of-production method is used to amortize our oil and natural gas properties. A change in the quantity of reserves could significantly impact our depletion expense. A reduction in proved reserves, without a corresponding reduction in capitalized costs, will increase our depletion rate. A 10% decrease in reserves would have increased our depletion expense by approximately $541,000, while a 10% increase in reserves would have decreased our depletion expense for the year ended December 31, 2016 by approximately $444,000.

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Unproved Property Costs

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

At December 31, 2016, we had $67.3 million allocated to unproved property costs, which was comprised primarily of unevaluated acreage costs. The unproven property costs are evaluated by the technical team and management to determine whether the property has potential attributable reserves. Therefore, the assessment made by our technical team and management of the potential reserves will determine whether costs are moved from the unproved category to the full-cost pool for depletion or whether an impairment is taken. A 10% increase or decrease in the unproved property balance would have decreased or increased our impairment cushion by approximately $6.5 million, respectively, for the year ended December 31, 2016.

Asset Retirement Obligation

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

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

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

Capitalized Interest

We capitalize interest on assets not being amortized, such as our unproven oil and natural gas properties. The methodology for capitalizing interest on general funds begins with a determination of the borrowings applicable to our qualifying assets. The basis of this approach is the assumption that the portion of the interest costs that are capitalized on expenditures during an asset's acquisition period could have been avoided if the expenditures had not been made. This methodology takes the view that if funds are not required for drilling and unproved property expenditures then they would have been used to pay off other debt. We use our best judgment in determining which borrowings represent the cost of financing the acquisition of the assets. The interest to be capitalized for any period is derived by multiplying the average rate of interest times the average qualifying assets during the period. To qualify for interest capitalization, we must continue to make progress on the development of the assets. Capitalized interest was approximately $3.1 million, $3.9 million and $4.3 million for 2016, 2015 and 2014, respectively.

Stock-Based Compensation

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

The Monte Carlo simulation valuation model requires a variety of inputs, including expected future stock price based on predictive assumptions of volatility, risk free rate, random numbers, the current stock price and forecast period. If any of the assumptions used in the Monte Carlo simulation valuation model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

Fair Value Measurement

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

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

Derivative Instruments and Hedging Activity

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

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

Recent Accounting Developments

For a discussion on recent accounting developments, see Note 2, “Summary of Significant Accounting Policies – Recent Accounting Developments” of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we were a party at December 31, 2016 and 2015, and from which we may incur future gains or losses from changes in market interest rates or commodity prices. We do not enter into derivative or other financial instruments for speculative trading purposes.

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

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Commodity Price Risk

Our major commodity price risk exposure is to the prices received for our oil, condensate, natural gas and NGLs production. Our results of operations and operating cash flows are affected by changes in market prices. Realized commodity prices received for our production are the spot prices applicable to oil, condensate, natural gas and NGLs in the region produced. Prices received for oil, condensate, natural gas and NGLs are volatile and unpredictable and are beyond our control. To mitigate a portion of our exposure to adverse market changes in the prices for oil, condensate, natural gas and NGLs, we have entered into, and may in the future enter into additional, commodity price risk management arrangements for a portion of our oil, condensate, natural gas and NGLs production. For the year ended December 31, 2016, a 10% change in the prices received for our oil, condensate, natural gas and NGLs production would have had an approximate $6.1 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. For the year ended December 31, 2015, a 10% change in the prices received for our oil, condensate, natural gas and NGLs production would have had an approximate $8.3 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. For more information regarding our hedging activities, see Item 8. “Financial Statements and Supplementary Data, Note 7. Derivative Instruments and Hedging Activity” included in this Form 10-K.

We are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, we do not anticipate non-performance by such counterparties.

Interest Rate Risk

We were exposed to changes in interest rates as a result of our Revolving Credit Facility. At December 31, 2016, we had $84.6 million of borrowings outstanding under our Revolving Credit Facility. Based on the amount outstanding under our Revolving Credit Facility at December 31, 2016, a one percentage point change in the interest rate would have had a per month impact of $71,000 on our interest expense. At December 31, 2015, we had $200.0 million of borrowings outstanding under our Revolving Credit Facility. Based on the amount outstanding under our Revolving Credit Facility at December 31, 2015, a one percentage point change in the interest rate would have had a per month impact of $167,000 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 did not believe such arrangements to be cost effective. The amount outstanding under the Former Notes was 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 as we believe this risk is minimal.

On March 3, 2017, we entered into a five-year $250.0 million first lien secured Term Loan that bears interest at a fixed rate of 8.5% and issued $125.0 million of Notes due 2022 that bear interest at a fixed rate of 6.0%. As a result of the transactions described above, on March 3, 2017, our Revolving Credit Facility was paid in full and terminated and the $325.0 million principal of outstanding Former Notes was satisfied and discharged. Thus, we have no exposure to fluctuating interest rates.

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Item 8. Financial Statements and Supplementary Data

GASTAR EXPLORATION INC. AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gastar Exploration Inc.

Houston, Texas

We have audited the accompanying consolidated balance sheets of Gastar Exploration Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company at December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 9, 2017 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Dallas, Texas

March 9, 2017

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GASTAR EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2016	2015
	(in thousands, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$71,529	$50,074
Accounts receivable, net of allowance for doubtful accounts of $1,953 and $0, respectively	26,883	14,302
Commodity derivative contracts	6,212	15,534
Prepaid expenses	755	5,056
Total current assets	105,379	84,966
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	67,333	92,609
Proved properties	1,253,061	1,286,373
Total natural gas and oil properties	1,320,394	1,378,982
Furniture and equipment	2,622	3,068
Total property, plant and equipment	1,323,016	1,382,050
Accumulated depreciation, depletion and amortization	(1,131,012)	(1,053,116)
Total property, plant and equipment, net	192,004	328,934
OTHER ASSETS:		
Commodity derivative contracts	1,638	9,335
Deferred charges, net	676	985
Advances to operators and other assets	102	331
Other	405	4,944
Total other assets	2,821	15,595
TOTAL ASSETS	$300,204	$429,495
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$8,867	$2,029
Revenue payable	6,690	5,985
Accrued interest	3,515	3,730
Accrued drilling and operating costs	2,615	2,010
Advances from non-operators	3,504	167
Commodity derivative contracts	338	—
Commodity derivative premium payable	1,654	3,194
Asset retirement obligation	89	89
Other accrued liabilities	2,462	6,764
Total current liabilities	29,734	23,968
LONG-TERM LIABILITIES:		

Long-term debt, net	404,493	516,476
Commodity derivative contracts	—	451
Commodity derivative premium payable	969	2,788
Asset retirement obligation	5,443	5,997
Total long-term liabilities	410,905	525,712
Commitments and contingencies (Note 13)		
STOCKHOLDERS' EQUITY:		
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 December 31, 2016 and 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 December 31, 2016 and 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 December 31, 2016 and 2015, respectively; 150,377,870 and 80,024,218 shares issued and outstanding at December 31, 2016 and 2015, respectively	150	80
Additional paid-in capital	644,306	571,947
Accumulated deficit	(784,953)	(692,274)
Total stockholders' equity	(140,435)	(120,185)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$300,204	$429,495

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

GASTAR EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands, except share and per share data)		
REVENUES:			
Oil and condensate	$43,011	$58,668	$82,820
Natural gas	10,854	16,901	47,647
NGLs	7,252	7,136	21,382
Total oil and condensate, natural gas and NGLs revenues	61,117	82,705	151,849
(Loss) gain on commodity derivatives contracts	(2,863)	24,589	19,569
Total revenues	58,254	107,294	171,418
EXPENSES:			
Production taxes	1,908	2,877	6,733
Lease operating expenses	20,605	23,728	19,323
Transportation, treating and gathering	1,704	2,187	3,679
Depreciation, depletion and amortization	29,673	62,887	46,180
Impairment of natural gas and oil properties	48,497	426,878	—
Accretion of asset retirement obligation	368	502	506
General and administrative expense	19,445	17,069	16,485
Litigation settlement benefit	(10,100)	—	—
Total expenses	112,100	536,128	92,906
(LOSS) INCOME FROM OPERATIONS	(53,846)	(428,834)	78,512
OTHER (EXPENSE) INCOME:			
Interest expense	(35,246)	(30,686)	(27,571)
Investment and other income	31	13	19
Foreign transaction loss	—	—	(7)
(LOSS) INCOME BEFORE PROVISION FOR INCOME TAXES	(89,061)	(459,507)	50,953
Provision for income taxes	—	—	—
NET (LOSS) INCOME	(89,061)	(459,507)	50,953
Dividends on preferred stock	(3,618)	(14,473)	(14,424)
Undeclared cumulative dividends on preferred stock	(10,855)	—	—
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(103,534)	$(473,980)	$36,529
NET (LOSS) INCOME PER SHARE OF COMMON STOCK			

ATTRIBUTABLE TO COMMON STOCKHOLDERS:			
Basic	$(0.93)	$(6.11)	$0.58
Diluted	$(0.93)	$(6.11)	$0.55
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:			
Basic	111,367,452	77,511,677	63,270,733
Diluted	111,367,452	77,511,677	66,492,589

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

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GASTAR EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-in	Accumulated	
	Shares	Amount	Shares	Amount	Shares	Amount	Capital	Deficit	Total Equity
	(in thousands, except share data)								
Balance at December 31, 2013	3,958,160	$ 40	2,140,000	$ 21	61,211,658	$ 61	$ 464,730	$ (254,823)	$ 210,029
Issuance of preferred stock	86,840	1	—	—	—	—	2,065	—	2,066
Issuance of common shares - cash, net of offering costs of $4,931	—	—	—	—	17,000,000	17	101,302	—	101,319
Issuance of common shares - PBUs vesting, net of forfeitures	—	—	—	—	472,189	—	—	—	—
Issuance of restricted stock	—	—	—	—	601,473	—	—	—	—
Forfeitures of restricted stock	—	—	—	—	(659,227)	—	(4,562)	—	(4,562)
Exercise of stock options, net of forfeitures	—	—	—	—	6,717	—	15	—	15
Stock-based compensation	—	—	—	—	—	—	4,890	—	4,890
Preferred stock dividends	—	—	—	—	—	—	—	(14,424)	(14,424)
Net income	—	—	—	—	—	—	—	50,953	50,953
Balance at December 31, 2014	4,045,000	$ 41	2,140,000	$ 21	78,632,810	$ 78	$ 568,440	$ (218,294)	$ 350,286
Issuance of common shares - PBUs vesting, net of forfeitures	—	—	—	—	497,636	1	(1)	—	—
Issuance of restricted stock	—	—	—	—	1,426,604	1	(1)	—	—
	—	—	—	—	(532,832)	—	(1,472)	—	(1,472)

Forfeitures of restricted stock									
Stock-based compensation	—	—	—	—	—	—	4,981	—	4,981
Preferred stock dividends	—	—	—	—	—	—	—	(14,473)	(14,473)
Net loss	—	—	—	—	—	—	—	(459,507)	(459,507)
Balance at December 31, 2015	4,045,000	$ 41	2,140,000	$ 21	80,024,218	$ 80	$ 571,947	$ (692,274)	$ (120,185)
Issuance of common shares - cash, net of offering costs of $2,687	—	—	—	—	50,000,000	50	44,763	—	44,813
Issuance of common shares under ATM - cash, net of offering costs of $557	—	—	—	—	18,606,943	19	24,392	—	24,411
Issuance of common shares - PBUs vesting, net of forfeitures	—	—	—	—	502,593	1	(1)	—	—
Issuance of restricted stock	—	—	—	—	1,764,645	1	(1)	—	—
Forfeitures of restricted stock	—	—	—	—	(520,529)	(1)	(712)	—	(713)
Stock-based compensation	—	—	—	—	—	—	3,918	—	3,918
Preferred stock dividends	—	—	—	—	—	—	—	(3,618)	(3,618)
Net loss	—	—	—	—	—	—	—	(89,061)	(89,061)
Balance at December 31, 2016	4,045,000	$ 41	2,140,000	$ 21	150,377,870	$ 150	$ 644,306	$ (784,953)	$ (140,435)

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

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GASTAR EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31, 2016	2015	2014
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$(89,061)	$(459,507)	$50,953
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	29,673	62,887	46,180
Impairment of natural gas and oil properties	48,497	426,878	—
Stock-based compensation	3,918	4,981	4,890
Mark to market of commodity derivatives contracts:			
Total loss (gain) on commodity derivatives contracts	2,863	(24,589)	(19,569)
Cash settlements of matured commodity derivative contracts, net	13,110	24,910	(4,901)
Cash premiums paid for commodity derivatives contracts	(565)	(45)	(185)
Amortization of deferred financing costs	4,980	3,584	3,067
Accretion of asset retirement obligation	368	502	506
Settlement of asset retirement obligation	(307)	(83)	(588)
Loss on sale of furniture and equipment	97	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(14,850)	19,333	(12,524)
Prepaid expenses	4,301	(2,973)	(938)
Accounts payable and accrued liabilities	3,713	(4,606)	(2,566)
Net cash provided by operating activities	6,737	51,272	64,325
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development and purchase of oil and natural gas properties	(59,922)	(148,182)	(155,631)
Reimbursements from (advances to) operators	576	(2,302)	(61,067)
Acquisition of oil and natural gas properties - refund (expenditure)	1,143	(45,575)	4,209
Proceeds from sale of oil and natural gas properties	121,273	47,314	5,530
Proceeds from (payments to) non-operators	3,337	(1,653)	(7,439)
Sale (purchase) of furniture and equipment	73	(58)	(319)
Net cash provided by (used in) investing activities	66,480	(150,456)	(214,717)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of common shares, net of issuance costs	69,224	—	101,319
Proceeds from revolving credit facility	—	196,000	103,000
Repayment of revolving credit facility	(115,370)	(41,000)	(58,000)
Proceeds from issuance of preferred stock, net of issuance costs	—	—	2,064
Dividends paid on preferred stock	(3,618)	(14,473)	(14,424)
Deferred financing charges	(1,285)	(805)	(405)
Tax withholding related to restricted stock and PBU vestings	(713)	(1,472)	(4,562)
Other	—	—	15

Net cash (used in) provided by financing activities	(51,762)	138,250	129,007
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	21,455	39,066	(21,385)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	50,074	11,008	32,393
CASH AND CASH EQUIVALENTS, END OF PERIOD	$71,529	$50,074	$11,008

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

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GASTAR EXPLORATION INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Gastar Exploration Inc. (“Gastar” or the “Company”) is a pure-play Mid-Continent independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and natural gas liquids (“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 Meramec and Osage formations within the Mississippi Lime, the Oswego limestone, the Woodford shale and Hunton limestone formations. These formations are what is commonly referred to as the “STACK Play”. 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

Basis of Presentation

The consolidated financial statements of the Company are stated in U.S. dollars unless otherwise noted and have been prepared by management in accordance with accounting principles generally accepted in the U.S.(“GAAP”). The preparation of these financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, related disclosure of contingent assets and liabilities, proved oil and natural gas reserves and the related disclosures in the accompanying consolidated financial statements. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows. See Note 17. “Supplemental Oil and Gas Disclosures.”

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).

Subsequent Events

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

Preferred Dividends

On January 10, 2017, the Company, together with the parties thereto, entered into Amendment No. 10 to the Second Amended and Restated Credit Agreement ("Amendment No. 10"), dated as of January 10, 2017. Amendment No. 10, among other things, permitted the limited payment of certain cash dividends on the Company's preferred stock, including the dividends declared payable on January 31, 2017, provided that (1) the Company's borrowing base will be correspondingly reduced in the amount of any such dividend payment and (2) the Company pays down its outstanding indebtedness under the Revolving Credit Facility in the amount of any resulting borrowing base deficiency. Under Amendment No. 10, payment of the declared January 2017 dividend and monthly preferred stock cash dividends through May 2017 was permitted contingent upon the satisfaction of certain conditions, including but not limited to, (1) the absence of any defaults or borrowing base deficiency, (2) for any dividends declared and paid in respect of April 2017 and May 2017, having cash liquidity (including any available borrowings under the Revolving Credit Facility) of more than $30.0 million and (3) paying any permitted dividends solely from proceeds received by the Company from sales of equity since November 30, 2016 (including through the Company's at-the-market sales program). The Company paid all accumulated and unpaid dividends for the period April 2016 to December 2016, as well as the January 2017, preferred dividend payment on January 31, 2017. Under the agreement pursuant to which the Term Loan is issued and the indenture governing the Notes, cash dividend payments on the Company's outstanding preferred stock are permitted through July 31, 2018 contingent upon the absence of any defaults. From and after August 1, 2018, dividend payments on the Series A and Series B Preferred Stock are permitted subject to the Company's compliance with a certain fixed charge coverage ratio test.

Stockholder Rights Agreement

On January 27, 2017, the Company's board of directors adopted a replacement stockholder rights plan (the "2017 Rights Agreement") to effectively replace the stockholders rights plan adopted on January 18, 2016 (the "2016 Rights Agreement"). As of January 18, 2017, the 2016 Rights Agreement expired pursuant to its terms. Pursuant to the 2017 Rights Agreement, the Company's board of directors declared a non-taxable dividend of one preferred share purchase right (each, a "Right") for each of the Company's issued and outstanding shares of common stock. The dividend was paid to stockholders of record on February 10, 2017. Each Right entitles the registered holder, subject to the terms of the 2017 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 $10.74, subject to certain adjustments. The purpose of the 2017 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.

Ares Investment Transaction

On March 3, 2017 (the "Closing Date"), the Company closed the previously announced capital and refinancing transactions (the "Ares Investment Transaction") with certain funds (the "Purchasers") affiliated with Ares Management, L.P. ("Ares").

Securities Purchase Agreement

On February 16, 2017, the Company entered into a Securities Purchase Agreement (the "Purchase Agreement") with the Purchasers, pursuant to which the Company issued and sold for cash to the Purchasers (i) $125.0 million aggregate principal amount of its Convertible Notes due 2022 (the "Notes"), which Notes, subject to the receipt of approval of the Company's stockholders, will be convertible into common stock, par value $0.001 per share of the Company (the "Common Stock") or, in certain circumstances, cash in lieu of Common Stock or a combination of cash and shares of Common Stock as described below and (ii) 29,408,305 shares of Common Stock for a purchase price of $50.0 million. In addition, an affiliate of Ares concurrently loaned the Company $250.0 million pursuant to a senior secured first-lien term loan as further described below (the "Term Loan"). The proceeds from the sale of the Notes, the Common Stock and the Term Loan were used to fully repay the $69.2 million outstanding on the Company's revolving credit facility and to satisfy and discharge its $325.0 million of 8.625% senior secured notes due May 2018, which will be redeemed at a price of 102.156% of their principal amount on March 24, 2017, and to pay the expenses from the Ares Investment Transaction. The issuance of Common Stock and the Notes were consummated as a private placement to "accredited investors" (as that term is defined under Rule 501 of Regulation D), exempt from registration under the Securities Act of 1933, as amended (the "Securities Act"), in reliance upon Section 4(a)(2) of the Securities Act and Regulation D Rule 506, as a transaction by an issuer not involving a public offering.

The issuance of the shares of Common Stock to the Purchasers was priced based on a 30-trading day volume weighted average trading price (the "VWAP") of $1.7002 per share, determined as of February 15, 2017, the date immediately prior to the signing date of the Purchase Agreement. This resulted in the issuance of 29,408,305 shares of Common Stock to the Purchasers, or approximately 18.8% of the shares of the Company's 156,715,833 shares of Common Stock issued and outstanding as of January 31, 2017. For so long as the Purchasers, collectively, beneficially own 10% or more of the Common Stock (including for this purpose all shares of Common Stock issuable upon conversion of the Notes), the Purchasers will have certain preemptive rights to purchase their pro rata share of any additional equity securities offered by the Company in the future on similar terms as are offered to other purchasers.

On March 2, 2017, the Company entered into Amendment No. 1 to the Purchase Agreement (the "Amendment") with the Purchasers. The Amendment amended the director nomination rights described below and the requisite ownership thresholds to exclude holders of any warrants or other convertible securities to satisfy the applicable NYSE MKT rules and regulations.

Pursuant to the Purchase Agreement, as amended by the Amendment, and so long as the Purchasers beneficially own (excluding ownership of Voting Stock (as defined in the Purchase Agreement) that such person only has the right to acquire) at least 15% of the total outstanding voting power of the Company's Voting Stock, the Purchasers will be entitled to nominate two directors to an expanded eight-member board of directors of the Company. If the Purchasers beneficially own (excluding ownership of Voting Stock that such person only has the right to acquire) 5% or more, but less than 15%, of the total outstanding voting power of the Company's Voting Stock, the Purchasers will be entitled to nominate one director to the board of directors of the Company.

Term Loan

On the Closing Date, the Company entered into the Third Amended and Restated Credit Agreement among the Company, as borrower, the guarantor party thereto, AF V Energy I Holdings, L.P., an affiliate of Ares, as initial lender, and Wilmington Trust, National Association, as administrative agent. The loans made pursuant to the Term Loan bear interest a per annum rate equal to 8.5%, payable on a quarterly basis on each March 1, June 1, September 1 and December 1 of each year, commencing on June 1, 2017. The Term Loan has a scheduled maturity of March 3, 2022. In addition, the Term Loan is subject to an interest "make-whole" and repayment premium, such that any repayment or prepayment of the loans thereunder prior to the stated maturity date shall be subject to the payment of a repayment premium, and depending on the date of such repayment or prepayment, the applicable interest "make-whole" amount, with the amount of such repayment premium decreasing over the life of the Term Loan.

The Term Loan is guaranteed by the Company's domestic subsidiary (excluding certain insignificant subsidiaries) and will be guaranteed by all of the Company's future domestic subsidiaries formed during the term of the Term Loan. The Term Loan is secured by a first-priority lien on substantially all of the assets of the Company as its subsidiary, excluding certain assets as customary exceptions.

The Term Loan contains various customary covenants for credit facilities of this type, including, among others, restrictions on granting liens, incurrence of other indebtedness, payments of certain dividends and other restricted payments, engaging in transactions with affiliates, dispositions of assets and other covenants, in each case subject to certain baskets and exceptions.

All outstanding amounts owed under the Term Loan become due and payable upon the occurrence of certain usual and customary events of default, including among others: (i) failure to make payments; (ii) non-performance of covenants and obligations continuing beyond any applicable grace period; and (iii) the occurrence of a change in control of the Company, as defined in the Term Loan.

The Company does not expect that the covenants or other provisions of the Term Loan or the Notes will restrict the payment of dividends on the Company's outstanding preferred stock through July 2018, and, thereafter, such payments will be subject to satisfaction of certain financial conditions. Any future dividends on such preferred stock, however, remain subject to declaration by the Company, and there is no assurance that the Company will declare and pay any future dividends, even if it is permitted to do so under the terms of the Term Loan or the Notes.

Indenture and Notes

On the Closing Date, the Company entered into an indenture (the "Indenture") by and among the Company, the subsidiary guarantor named therein, and Wilmington Trust, National Association, as trustee (the "Trustee") and collateral trustee, with respect to the Notes. The principal terms of the Notes are governed by the Indenture. Pursuant to the Indenture, the Notes were issued for cash at par, bear interest initially at 6.0% per annum and will mature on March 1, 2022, unless earlier repurchased, redeemed or converted in accordance with the terms of the Indenture. Interest is payable on the Notes on each March 1, June 1, September 1 and December 1 of each year, commencing on June 1, 2017.

Subject to receipt of stockholder approval on or before July 3, 2017 of the issuance of Common Stock upon conversion of the above Notes (the "Requisite Stockholder Approval"), the Notes will be convertible at the option of the holder into shares of Common Stock based on an initial conversion rate of 452.4355 shares of Common Stock per $1,000 principal amount of the Notes (which is equivalent to an initial conversion price of approximately $2.21 per share, or 30% above the VWAP per share of Common Stock for the 30 trading days prior to execution of the Purchase Agreement), subject to certain adjustments and the issuance of additional "make-whole" shares under circumstances specified in the Indenture. Subject to certain limitations, the Company will have the right to settle its conversion obligations on the Notes in cash, shares of Common Stock or a combination of cash and shares of Common Stock. If the Company obtains the Requisite Stockholder Approval, then the Company will have the right to redeem the Notes (i) on or after March 3, 2019, if the last reported sale price per share of Common Stock exceeds 150% of the conversion price for periods specified in the Indenture; and (ii) on or after March 1, 2021 without regard to such condition, in each case at cash redemption price equal to the principal amount of the Notes to be redeemed plus accrued interest, if any. The interest rate, conversion rate and other financial terms of the Notes were determined by negotiations between the Company and the Purchasers. The interest rate on the Notes will be subject to an increase in certain circumstances if the Company fails to obtain Requisite Stockholder Approval or to comply with certain obligations under the Registration Rights Agreement (as defined below), or in the case of certain issuances of Common Stock at below $1.7002 per share (subject to adjustment).

The Notes will be secured by a second-priority lien on substantially all of the assets of the Company. The Indenture restricts the ability of the Company and certain of its subsidiaries to, among other things: (i) pay dividends or make other distributions in respect of the Company's capital stock or make other restricted payments; (ii) incur additional indebtedness and issue preferred stock; (iii) make certain dispositions and transfers of assets; (iv) engage in transactions with affiliates; (v) create liens; (vi) engage in certain business activities that are not related to oil and gas; and (vii) impair any security interest. These covenants are subject to a number of exceptions and qualifications.

The Indenture provides that a number of events will constitute an Event of Default (as defined in the Indenture), including, among other things: (i) a failure to pay the Notes when due at maturity, upon redemption or repurchase; (ii) failure to pay interest for 30 days; (iii) the Company's failure to deliver certain notices; (iv) a default in the Company's obligation to convert the Notes; (v) the Company's failure to comply with certain covenants relating to merger, consolidation or sale of assets; (vi) the Company's failure to

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comply, for 60 days following notice, with any of the other covenants or agreements in the Indenture; (vii) a default, which is not cured within 30 days, by the Company or any Restricted Subsidiaries (as defined in the Indenture) with respect to any mortgages or any indebtedness for money borrowed of at least $15 million; (viii) one or more final judgments against the Company or any of its Restricted Subsidiaries for the payment of at least $15 million; (ix) the Company's failure to make any payments required under that certain development agreement; (x) causing any Guarantee (as defined in the Indenture) to cease to be in full force and effect; (xi) the cessation to be in full force and effect of any of the collateral agreements related to the Ares Investment Transaction; and (xii) certain events of bankruptcy or insolvency. In the case of an Event of Default arising from certain events of bankruptcy or insolvency with respect to the Company, all outstanding Notes will become due and payable immediately without further action or notice. If any other Event of Default occurs and is continuing, the Trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Notes may declare all the Notes to be due and payable immediately. If Requisite Stockholder Approval is not obtained, then upon any acceleration of the Notes following an Event of Default, holders will be entitled to receive a "make-whole" premium in addition to principal and accrued interest.

If stockholders do not approve the conversion rights of the Notes into Common Stock within four months of the Closing Date, the Notes will not be convertible and the interest rate on the Notes will increase in increments to 15% per annum, and will not be redeemable by the Company prior to maturity except upon payment of a "make-whole" redemption premium.

If at least a majority of the Notes issued pursuant to the Purchase Agreement cease to be held by affiliates of Ares after receipt of Requisite Stockholder Approval as provided in the Indenture, the liens securing the Notes will be released and substantially all of the restrictive covenants in the Indenture will terminate.

Registration Rights Agreement

On the Closing Date, the Company entered into a Registration Rights Agreement (the "Registration Rights Agreement") with the Purchasers, pursuant to which the Company has agreed that the future resale of the Common Stock sold in the Ares Investment Transaction and the shares of Common Stock issued upon conversion of the Notes will be registered under the Securities Act. The Registration Rights Agreement includes a plan of distribution permitting the Purchasers to sell the covered Common Stock by various means, including in open market sales from time to time, pursuant to underwritten offerings or in negotiated sales. The failure to (i) file a registration statement prior to July 3, 2017, (ii) have the registration statement declared effective within four months of the filing date for the Company's 2016 Annual Report on From 10-K or (iii) thereafter, with certain exceptions, maintain the effectiveness of the registration statement, will result in additional interest accruing on the Notes for so long as they are outstanding. The Company will be required to cooperate in a maximum of four underwritten offerings under the Registration Rights Agreement at the expense of the Company (other than underwriting discounts).

Intercreditor Agreement

On the Closing Date, Wilmington Trust, National Association, as administrative agent for the priority lien secured parties, and Wilmington Trust, National Association, as the second lien agent for the second lien secured parties, entered into an intercreditor agreement, which was acknowledged and agreed to by the Company and its subsidiary guarantor (the "Intercreditor Agreement") to govern the relationship of the lenders under the Term Loan and the holders of any other priority lien obligations on the one hand, and the noteholders and holders of any other second lien obligations that the Company may issue in the future, with respect to the sharing of collateral, the priority of the liens thereon and certain other matters.

Swap Intercreditor Agreement

On the Closing Date, Morgan Stanley Capital Group, Inc., NextEra Energy Marketing, LLC, Cargill, Incorporated, Koch Supply & Trading, LP, (collectively, the “Swap Counterparties”), the Company, the guarantor party thereto, Wilmington Trust, National Association, as administrative agent for the lenders from time to time party to the Term Loan, and Wilmington Trust, National Association, as collateral agent on behalf of the secured parties (the “Collateral Agent”) entered into an intercreditor agreement (the “Swap Intercreditor Agreement”) pursuant to which the Collateral Agent will receive, hold, administer, maintain, enforce and distribute the proceeds of all of the loan obligations, swap obligations and its liens upon the collateral for the benefit of the current and future lenders under the Term Loan and the Swap Counterparties.

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Principles of Consolidation

The consolidated financial statements of the Company include the consolidated accounts of all its subsidiaries. All significant inter-company accounts and transactions have been eliminated in consolidation.

Use of estimates in Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the Company’s financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes including uncertain tax positions, stock-based compensation, valuation of commodity derivatives contracts, future development and abandonment costs, estimates related to certain oil, condensate, natural gas and NGLs revenues and operating expenses, and the estimates of proved oil, condensate, natural gas and NGLs reserve quantities that are used to calculate depletion and impairment of proved oil and natural gas properties.

Cash and Cash Equivalents

The Company's cash and cash equivalents, which includes short-term investments such as money market deposits with a maturity of three months or less when purchased, amounted to $71.5 million and $50.1 million as of December 31, 2016 and 2015, respectively. The Company maintains its cash in bank deposit accounts, which, at times, may exceed federally insured limits. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant risk of loss.

Accounts Receivable

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

	For the years ended December 31,		
	2016	2015	2014
	(in thousands)		
Allowance for doubtful accounts, beginning of year	$—	$ —	$507

Expense	1,953	—	—
Reductions/write-offs	—	—	(507)
Allowance for doubtful accounts, end of year	$1,953	$ —	$—

Oil and Natural Gas Properties

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

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated net proved reserves, as determined by independent petroleum engineers.

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

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

The Company’s estimate of proved reserves is based on the quantities of oil, condensate, natural gas and NGLs that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. As discussed below, the estimate of the Company’s proved reserves as of December 31, 2016 and 2015 have been prepared and presented in accordance with current rules and accounting standards promulgated by the Securities and Exchange Commission (the “SEC”). These rules require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on a 12-month unweighted arithmetic average of the first-day-of-the-month price.

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

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

Asset Retirement Obligation

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

Furniture and Equipment

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

Capitalized Interest

The Company capitalizes interest on assets not being amortized related to specific projects such as its drilling in progress and unproven oil and natural gas property expenditures. The methodology for capitalizing interest on general funds begins with a determination of the borrowings applicable to the qualifying assets. The basis of this approach is the assumption that the portion of the interest costs that are capitalized on expenditures during an asset’s acquisition period could have been avoided if the expenditures had not been made. This methodology takes the view that if funds are not required for construction then they would have been used to pay off debt. The Notes and Revolving Credit Facility were included in the rate calculation of capitalized interest incurred for the year-ended December 31, 2016. The interest to be capitalized for any period is derived by multiplying the average rate of interest times the average qualifying assets during the period, not to exceed the total interest on the qualifying debt instruments. To qualify for interest capitalization, the Company must continue to make progress on the development of the assets. Capitalized interest costs were approximately $3.1 million, $3.9 million and $4.3 million for 2016, 2015 and 2014, respectively.

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Fair Value of Financial Instruments

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

Deferred Financing Costs

Deferred financing costs include costs of debt financings undertaken by the Company, including commissions, legal fees and other direct costs of financing. Using the effective interest method, the deferred financing costs are amortized over the term of the related debt instrument to interest expense. Deferred financing costs are presented as a direct reduction to the carrying amount of the related debt liability where the debt liability is not a line-of-credit arrangement.

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

	As of December 31,	
	2016	2015
Deferred charges	$2,971	$1,686
Accumulated amortization	(2,295)	(701)
Deferred charges, net	$676	$985

Derivative Instruments and Hedging Activity

The Company uses derivative instruments in the form of commodity costless collars, index swaps, basis and fixed price swaps and put and call options to manage price risks resulting from fluctuations in commodity prices of oil, condensate, natural gas and NGLs associated with future production. Derivative instruments are recorded on the balance sheet at fair value, and changes in the fair value of derivatives are recorded each period in current earnings. Fair value is assessed, measured and estimated by obtaining forward commodity pricing, credit adjusted risk-free interest rates and, as necessary, estimated volatility factors. The fair values that the Company reports in its consolidated financial statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond the Company’s control. Gains and losses on derivatives are included in total revenue within the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities. See Note 7, “Derivative Instruments and Hedging Activity.”

The Company has elected not to designate derivative contracts as cash flow hedges. As a result, any changes in the fair values of derivative contracts for future production are recognized in gain (loss) on commodity derivatives contracts within the Company’s consolidated statements of operations. Gains or losses from the settlement of matured commodity derivatives contracts are included in gain (loss) on commodity derivatives contracts in the Company’s consolidated statement of operations.

Stock-Based Compensation

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

Stock-based compensation cost for restricted shares is estimated at the grant date based on the award’s fair value, which is equal to the prior day’s closing stock price. Such fair value is recognized as expense over the requisite service period. Stock-based compensation cost for PBUs is estimated at the grant based on the award’s fair value, which is calculated using a Monte Carlo Simulation model. The Monte Carlo Simulation model uses a stochastic process to create a range of potential future outcomes given a variety of inputs, including expected future stock price based on predictive assumptions of volatility, risk free rate, random numbers, the current stock price and forecast period. Such fair value is recognized as expense over the requisite service period. Forfeitures of unvested stock options and restricted common shares historically were calculated at the beginning of the year as a percentage of all stock option and restricted common share grants. Beginning in 2017, the Company will no longer apply a forfeiture rate at grant and will account for forfeitures as they occur. For 2016, 2015 and 2014, the Company used forfeiture rates in determining compensation expense of 19.1%, 17.5% and 25.5%, respectively.

Treasury Stock

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

Revenue Recognition

The Company uses the sales method of accounting for the sale of its oil, condensate, natural gas and NGLs and records revenues from the sale of such products when delivery to the customer has occurred and title has transferred. This recording of revenues occurs when oil, condensate, natural gas or NGLs have been delivered to a pipeline or a tank lifting has occurred. The Company's NGLs are sold as part of the wet gas subject to an incremental NGLs pricing formula based upon a percentage of NGLs extracted from the Company's wet gas production. The Company's reported production volumes reflect incremental post-processing NGLs volumes and residual gas volumes with which the Company is credited under its sales contracts. Under the sales method, revenues are recorded based on the Company's net revenue interest, as delivered. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. The Company had no material gas imbalances at December 31, 2016, 2015 and 2014.

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

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

Deferred Income Taxes

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

Comprehensive Income

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

Earnings or Loss per Share

Basic earnings or loss per share is computed by dividing net income (loss) available to common stockholders, net of accumulated paid and unpaid dividends, by the weighted average number of shares of common stock outstanding. Diluted earnings or loss per share is computed by dividing net income (loss) available to common stockholders, net of accumulated and unpaid dividends, by the weighted average number of shares of common stock outstanding plus the incremental effect of the assumed issuance of common stock for all potentially dilutive securities. Diluted per share amounts reflect the potential dilution that could occur if

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securities or other contracts to issue common stock are exercised or converted to common stock. The treasury stock method is used to determine the dilutive effect of unvested restricted shares and PBUs.

Co-participation Operations

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

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and natural gas. The Company’s current operational activities and the Company’s consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long-lived assets located outside the U.S.

Foreign Currency Exchange

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

All of the Company’s operations are conducted in U.S. dollars. The Company owns immaterial non-operating working interests in two natural gas wells located in Alberta, Canada, from which it has received no revenue since January 1, 2012.

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

Recent Accounting Developments

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

Business Combinations. In January 2017, the Financial Accounting Standards Board (“FASB”) issued updated guidance to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments in this update provide a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, the amendments in this update (1) require that to be considered a business, a set must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create output and (2) remove the evaluation of whether a market participant could replace missing elements. The amendments in this update affect all reporting entities that must determine whether they have acquired or sold a business and are effective for public business entities for annual reporting periods beginning after December 15, 2017, including interim periods within those periods. The amendments should be applied prospectively on or after the effective date and no disclosures are required at transition. Early application is allowed as follows (1) for transactions for which the acquisition date occurs before the issuance date or effective date of the amendments, only when the transaction has not been reported in financial statements that have been issued or made available for issuance and (2) for transactions in which a subsidiary is deconsolidated or a group of assets is derecognized that occur before the issuance date or effective date of the amendments, only when the transaction has not been reported in financial statements that have been issued or made available for issuance. Due to its application to future acquisitions and disposals, the adoption of this guidance, effective January 1, 2018, will not have any immediate effect on our financial position or results of operations.

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 amendment provides guidance on the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions;

and separately identifiable cash flows and application of the predominance principle. 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 is currently evaluating the effect that adopting this guidance will have on its presentation of cash flows. The Company does not believe the effects of adopting this updated guidance will have a material effect on its statement of cash flows and it is expected to have no effect on the Company’s financial position or results of operations.

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 adopted this updated guidance for the fiscal year beginning January 1, 2017 and will record an adjustment of approximately $657,000 to retained earnings on a modified retrospective basis to properly reflect the adjustment to stock compensation expense to reduce the forfeiture rate to 0%.

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 begun analyzing its lease contracts but 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 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 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 issuance of the 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. The Company has adopted this guidance as of December 31, 2016 and there is no impact on its consolidated financial statements.

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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 currently determining the impacts of the new revenue recognition standard on its contracts. The Company's approach includes evaluating its key revenue contracts representative of its revenue and comparing historical accounting policies and practices to the new standard. The Company's revenue contracts are primarily normal purchase/normal sale contracts with index pricing that settle monthly and as such, the Company does not expect that the new revenue recognition standard will have a material impact on its financial statements upon adoption. The Company intends to apply the new standard utilizing a modified retrospective basis that could result in a cumulative effect adjustment as of January 1, 2018.

3. Property, Plant and Equipment

The amount capitalized as oil and natural gas properties was incurred for the purchase and development of various properties in the U.S., specifically the states of 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 assets in the Appalachian Basin. On January 20, 2017, the Company sold its remaining interest in producing wells and undeveloped acreage in West Virginia, effective January 1, 2017, for $200,000. The Company's total property, plant and equipment consists of the following:

	December 31,	
	2016	2015
	(in thousands)	
Oil and natural gas properties, full cost method of accounting:		
Unproved properties	$67,333	$92,609
Proved properties	1,253,061	1,286,373

Total oil and natural gas properties	1,320,394	1,378,982
Furniture and equipment	2,622	3,068
Total property and equipment	1,323,016	1,382,050
Impairment of proved natural gas and oil properties	(813,314)	(764,817)
Accumulated depreciation, depletion and amortization	(317,698)	(288,299)
Total accumulated depreciation, depletion and amortization	(1,131,012)	(1,053,116)
Total property and equipment, net	$192,004	$328,934

Included in the Company's oil and natural gas properties are asset retirement costs of $1.5 million and $2.4 million as of December 31, 2016 and 2015, respectively.

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

	December 31,	
	2016	2015
	(in thousands)	
Unproved properties, excluded from amortization:		
Drilling in progress costs	$1,100	$1,533
Acreage acquisition costs	58,857	82,560
Capitalized interest	7,376	8,516
Total unproved properties excluded from amortization	$67,333	$92,609

For the year ended December 31, 2015, management's evaluation of unproved properties resulted in an impairment. Due to continued lower natural gas prices for natural gas and no current plans to drill or extend leases in the Appalachian Basin, the Company reclassified $14.4 million of unproved properties to proved properties for the year ended December 31, 2015.

The full cost method of accounting for oil and natural gas properties requires a quarterly calculation of a limitation on capitalized costs, often referred to as a full cost ceiling calculation. The ceiling is the present value of estimated future cash flow from proved oil, condensate, natural gas and NGLs reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage) to the extent not included in oil and natural gas properties pursuant to authoritative guidance and estimated future income taxes thereon. To the extent that the Company's capitalized costs (net of accumulated depletion and deferred taxes) exceed the ceiling, the excess must be written off to expense 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 Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)[1]		$ 2.48	$ 2.28	$2.24	$2.40
West Texas Intermediate oil price (per Bbl)[1]		$ 42.75	$ 41.68	$43.12	$46.26
Impairment recorded (pre-tax) (in thousands)	$48,497	$ —	$ —	$—	$48,497

2015

	Total Impairment	December 31	September 30	June 30	March 31
Henry Hub natural gas price (per MMBtu)[1]		$2.59	$3.06	$3.39	$3.88
West Texas Intermediate oil price (per Bbl)[1]		$50.28	$59.21	$71.68	$82.72
Impairment recorded (pre-tax) (in thousands)	$426,878	$144,760	$181,966	$100,152	$—

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

(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 the future 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.

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The Company's estimated proved reserve volumes were 25.6 MMBoe at December 31, 2016 using the SEC-mandated historical twelve-month unweighted average pricing at such date.

Development Agreement

On October 14, 2016, the Company executed an agreement with STACK Exploration LLC, a Delaware limited liability company (the "Investor"), (the "Development Agreement") to jointly develop up to 60 Gastar operated wells in the STACK Play in Kingfisher County, Oklahoma (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 32,900 gross (19,100 net) undeveloped 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 the Company's working interest portion of drilling and completion costs to initially earn 80% of the Company's working interest in each new well (in each case, proportionately reduced by other participating working interests in the well). As a result, the Company will pay 10% of its working interest portion of such costs for 20% of its original working interest.

The 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 for its investment in the tranche, its interest will be reduced from 80% to 40% of the Company's original working interest and the Company's working interest increases from 20% to 60% of the Company's original working interest. When a tranche internal rate of return of 20% is achieved by the Investor, its working interest decreases to 10% and the Company's working interest increases to 90% of the working interest originally owned by the Company. The parties to the Development Agreement can mutually agree to expand the contract area and drilling formation focus.

Upon completion of a tranche, the Investor has the right, but not the obligation, for a period of six months to cause the Company to purchase the Investor's interest in the Drilling Program that is not subject to final reversion (the "WI Tail") for such tranche (the "Investor Put Right") for fair market value by applying the methodology to determine a 15% discounted present value as defined by the Development Agreement. If the Investor fails to exercise the Investor Put Right within the six-month period after achieving final reversion, then for a period of six months thereafter, the Company shall have the right, but not the obligation, to purchase the WI Tail from the Investor on the same fair market value approach of the Investor Put Right. If final reversion has not been achieved by the eighth anniversary of the spud date of the first well in a given tranche, Investor will, for a period of six months thereafter, have the right to cause us to buy Investor's then-current interest in such tranche at an agreed upon valuation.

As of December 31, 2016, the Company and the Investor had completed four gross wells, all of which were on production, within the first tranche of the Drilling Program. As of March 6, 2017, nine gross wells have been completed, all of which are on production.

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 ("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 and with a property sale effective date of August 1, 2016 ("South STACK Play Acreage Sale"). On November 18, 2016, the Company and Red Bluff executed and delivered two amendments to the sale agreement and entered into a relating closing agreement, which, among other things, allocated $1.4 million of the purchase price to producing properties with the remainder of the purchase price to non-producing properties. As of December 31, 2016, the Company had received approximately $48.6 million of sales proceeds from the South STACK Play Acreage Sale. An additional $9.5 million was received subsequent to December 31, 2016, which included $5.0 million of the contingent payment. The remaining sales proceeds are anticipated to be received by July 2017, subject to certain adjustments.

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 Sale for $80.0 million, subject to customary

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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 the 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 years ended December 31, 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 Years Ended December 31,	
	2016	2015
	(in thousands, except per share data) (Unaudited)	
Revenues	$55,177	$93,783
Net loss	$(98,459)	$(464,788)
Loss per share:		
Basic	$(0.88)	$(6.00)
Diluted	$(0.88)	$(6.00)

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The pro forma information above includes numerous assumptions, is presented for illustrative purposes only and may not be indicative of the future results or results of operations that would have actually occurred had the 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") and certain affiliates for an adjusted purchase price of approximately $42.7 million, net of $358,000 of revenue suspense liability assumed by the Company (the "Husky Acquisition"). The adjusted purchase price reflected an adjustment for an acquisition effective date of July 1, 2015 and included a $4.3 million deposit into escrow pending the resolution of title defects by the seller and the purchase of overrides recorded in other assets at December 31, 2015. Additionally, the Company conveyed approximately 11,000 net non-core, non-producing acres in Blaine, Major and Kingfisher Counties, Oklahoma to the sellers. As of December 31, 2016, all title defects had been resolved by the seller and the escrow funds had been released. 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 $1.5 million of transaction and integration costs associated with the acquisition and expensed these costs as incurred as general and administrative expenses. The Company utilized relevant market assumptions to determine fair value and allocate the purchase price, such as future commodity prices, projections of estimated natural gas and oil reserves, expectations for future development and operating costs, projections of future rates of production, expected recovery rates and market multiples for similar transactions. Many of the assumptions used are unobservable and as such, represent Level 3 inputs under the fair value hierarchy as described in Note 6, "Fair Value Measurements." The Company's preliminary assessment of the fair value of the 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.

The following table summarizes the fair value of the assets acquired and liabilities assumed in connection with the Husky Acquisition (in thousands):

Consideration:	
Cash consideration	$42,085
Conveyance of undeveloped acreage	—
Total purchase price	$42,085
Estimated Fair Value of Assets Acquired:	
Unproved properties	$27,875
Proved properties	15,592
Other	(1,382)
Total assets acquired	$42,085

Husky Acquisition Unaudited Pro Forma Operating Results

The following unaudited pro forma results for the year ended December 31, 2015 shows 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 Year Ended December 31, 2015 (in thousands, except per share data) (Unaudited)
Revenues	$ 115,147
Net loss	$ (470,874)
Loss per share:	
Basic	$ (6.07)
Diluted	$ (6.07)

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.

Mid-Continent Divestiture

On July 6, 2015, the Company sold certain non-core assets comprised of 38 gross (16.7 net) producing wells and approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma for an adjusted purchase price of $46.5 million. The 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 significant to the full cost pool.

4. Long-Term Debt

Ares Investment Transaction

On February 16, 2017, the Company entered into a Purchase Agreement with Purchasers affiliated with Ares pursuant to which the Company will issue and sell for cash to the Purchasers (i) $125.0 million aggregate principal amount of its Notes due 2022 sold at par, which Notes, subject to the receipt of approval of the Company's stockholders, will be convertible into Common Stock or, in certain circumstances, cash in lieu of Common Stock or a combination thereof as described below and (ii) 29,408,305 shares of Common Stock for a purchase price of $50.0 million. In addition, an affiliate of Ares has agreed to concurrently loan the Company $250.0 million pursuant to a first lien secured Term Loan. The Company completed the Ares Investment Transaction on March 3, 2017. Proceeds from the sale of the Notes, the Common Stock and the Term Loan will be used to fully repay and redeem the Company's existing $69.2

million Revolving Credit Facility and its $325.0 million senior secured notes due May 2018.

On March 3, 2017, the Company entered the Term Loan. The loans made pursuant to the Term Loan bear interest at a per annum rate equal to 8.5%, payable on a quarterly basis on each March 1, June 1, September 1 and December 1 of each year, commencing June 1, 2017. The Term Loan has a scheduled maturity of March 3, 2022. In addition, the Term Loan is subject to an interest "make-whole" and repayment premium, such that any repayment or prepayment of the loans thereunder prior to the stated maturity date shall be subject to the payment of a repayment premium, and depending on the date of such repayment or prepayment, the applicable interest "make-whole" amount, with the amount of such repayment premium decreasing over the life of the Term Loan.

The Term Loan is guaranteed by all of the Company's future domestic subsidiaries and will be guaranteed by all of the Company's future domestic subsidiaries formed during the term of the Term Loan. The Term Loan is secured by a first-priority lien on substantially all of the assets of the Company and its subsidiaries, excluding certain assets as customary exceptions.

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The Term Loan contains various customary covenants for credit facilities of this type, including, among others, restrictions on granting liens, incurrence of other indebtedness, payments of certain dividends and other restricted payments, engaging in transactions with affiliates, dispositions of assets and other, in each case subject to certain baskets and exceptions;

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

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

The issuance of Common Stock and the Notes will be consummated as a private placement to "accredited investors" (as that term is defined under Rule 501 of Regulation D), exempt from registration under the Securities Act, in reliance upon Section 4(a)(2) of the Securities Act and Regulation D Rule 506, as a transaction by an issuer not involving a public offering.

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"). The Revolving Credit Facility had a scheduled maturity of November 14, 2017.

On January 10, 2017, the Company, together with the parties thereto, entered into Amendment No. 10, which amended the Revolving Credit Facility to, among other things, permit the payment of certain cash dividends on its preferred stock, including the dividends declared payable on January 31, 2017, provided that (i) the Company's borrowing base will be correspondingly reduced in the amount of any such dividend payment and (ii) the Company pays down its outstanding indebtedness under the Revolving Credit Facility in the amount of any resulting borrowing base deficiency.

Under Amendment No. 10, payment of the declared January 2017 dividend and monthly preferred stock cash dividends through May 2017 is permitted contingent upon the satisfaction of certain conditions, including but not limited to, (i) the absence of any defaults or borrowing base deficiency, (ii) for any dividends declared and paid in respect of April 2017 and May 2017, having cash liquidity (including any available borrowings under the Revolving Credit Facility) of more than $30.0 million and (iii) paying any permitted dividends solely from proceeds received by the Company from sales of equity since November 30, 2016 (including through the Company's at-the-market issuance sales agreement with a third-party sales agent to sell, from time to time, shares of the Company's common stock (the "ATM Program"). Under Amendment No. 10, the Company also agreed to pay down indebtedness under its Revolving Credit Facility by at least an additional $8.1 million by April 30, 2017, which is anticipated to be paid out of proceeds received by such date from the South STACK Play Acreage Sale.

On March 3, 2017, the Company used a portion of the net proceeds from the Ares Investment Transaction to fully repay all of the $69.2 million borrowings outstanding under the Revolving Credit Facility (which was terminated on such date).

Senior Secured Notes

At December 31, 2016, the Company had $325.0 million aggregate principal amount of 8 5/8% Senior Secured Notes due May 15, 2018 (the "Former Notes") outstanding under an indenture (the "Former 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 Former Notes bore interest at a rate of 8.625% per year, payable semiannually in arrears on May 15 and November 15 of each year, beginning on November 15, 2013. 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 Former Indenture.

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

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	December 31, 2016	December 31, 2015
	(in thousands)	
Notes, principal balance	$325,000	$325,000
Less:		
Unamortized discounts	(4,342)	(7,151)
Deferred financing costs	(795)	(1,373)
Notes, net	$319,863	$316,476

On March 3, 2017, the redemption price plus interest of all of the Company's outstanding $325.0 million principal of 8 5/8% senior secured notes due 2018 (the "Former Notes") was funded to satisfy and discharge the Former Notes from a portion of the net proceeds from the Ares Investment Transaction, which have been irrevocably called for redemption on March 24, 2017.

Notes. On March 3, 2017, the Company issued for cash at par $125.0 million principal amount of the Notes under an indenture (the "Indenture") by and among the Company, the subsidiary guarantor named therein, and Wilmington Trust, National Association, as trustee (the "Trustee") and collateral trustee. The Notes bear interest at 6.0% per annum and will mature on March 1, 2022, unless earlier repurchased, redeemed or converted in accordance with the terms of the Indenture prior to such date. Interest is payable on the Notes on each March 1, June 1, September 1 and December 1 of each year, commencing June 1, 2017.

If holders of issued and outstanding common stock (other than shares recently issued to funds managed by affiliates of Ares) approve the conversion rights of the Notes on or before July 3, 2017 in a manner satisfactory to meet the requirements of The NYSE MKT (the "Requisite Stockholder Approval"), the Notes will become convertible at the option of the holder into shares of common stock based on an initial conversion price of $2.2103 per share, subject to certain adjustments and the issuance of additional "make-whole" shares under certain circumstances specified in the Indenture. Subject to certain limitations, the Company will have the right to settle its conversion obligations on the Notes in common stock, or in cash or a combination thereof. If the Company obtains the Requisite Stockholder Approval, then the Company will have the right to redeem the Notes (i) on or after March 3, 2019 if the common stock trades above 150% of the conversion price for periods specified in the Indenture; and (ii) on or after March 1, 2021 without regard to such condition, in each case at par plus accrued interest.

If the Requisite Stockholder Approval is not obtained on or before July 3, 2017, the Notes will not be convertible and the interest rate payable on the Notes will increase in increments to 15.0% per annum, and will not be redeemable by the Company prior to maturity except upon payment of a "make-whole" redemption premium. The interest rate on the Notes will also be subject to an increase in certain circumstances if the Company fails to comply with certain obligations under the Registration Rights Agreement (as defined below), or in the case of certain issuances of common stock at below the initial reference price of $1.7002 per share.

The Notes are secured by a second-priority lien on substantially all of the assets of the Company. The Indenture restricts the ability of the Company and certain of its subsidiaries to, among other things: (i) have an affiliate of the

Company acquire the Notes; (ii) pay dividends or make other distributions in respect of the Company’s capital stock or make other restricted payments; (iii) incur additional indebtedness and issue preferred stock; (iv) make certain dispositions and transfers of assets; (v) engage in transactions with affiliates; (vi) create liens; (vii) engage in certain business activities that are not related to oil and gas; and (viii) impair any security interest. These covenants are subject to a number of exceptions and qualifications.

5. Asset Retirement Obligation

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands)		
Asset retirement obligation, beginning of year	$6,086	$5,557	$6,063
Liabilities incurred during period	196	302	305
Liabilities settled during period	(90)	(37)	(704)
Accretion expense	368	502	506
Revision in previous estimates and other	17	178	32
Deletions related to property disposals	(1,045)	(416)	(645)
Asset retirement obligation, end of year	$5,532	$6,086	$5,557

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As of December 31, 2016, the current portion of the Company’s asset retirement obligation was $89,000 and was recorded in current liabilities on the consolidated balance sheet.

6. Fair Value Measurements

The Company’s financial assets and liabilities are measured at fair value on a recurring basis. The Company discloses its recognized non-financial assets and liabilities, such as asset retirement obligations, unproved properties and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. The Company assesses its unproved properties for impairment whenever events or circumstances indicate the carrying value of those properties may not be recoverable. The fair value of the unproved properties is measured using an income approach based upon internal estimates of future production levels, current and future prices, drilling and operating costs, discount rates, current drilling plans and favorable and unfavorable drilling activity on the properties being evaluated and/or adjacent properties, which are Level 3 inputs. For the year ended December 31, 2015, management’s evaluation of unproved properties resulted in an impairment. Due to continued lower natural gas prices for dry gas and no plans to drill or extend leases in the Appalachian Basin during 2015, the Company reclassified $14.4 million of unproved properties to proved properties for the year ended December 31, 2015. As no other fair value measurements are required to be recognized on a non-recurring basis at December 31, 2016, no additional disclosures are provided at December 31, 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 oil, natural gas and NGLs price risk. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs. The fair values derived from counterparties and third-party brokers are verified by the Company using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location. Although such counterparty and third-party broker quotes are used to assess the fair value of its 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.

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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 December 31, 2016 and 2015:

	Fair value as of December 31, 2016			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets:				
Cash and cash equivalents	$71,529	$ —	$—	$71,529
Commodity derivative contracts	—	—	7,850	7,850
Liabilities:				
Commodity derivative contracts	—	—	(338)	(338)
Total	$71,529	$ —	$7,512	$79,041

	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 years ended December 31, 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 December 31, 2016 and 2015.

	For the Years Ended December 31,	
	2016	2015
	(in thousands)	
Balance at beginning of period	$24,418	$27,502
Total (losses) gains included in earnings	(2,863)	24,589
Purchases	565	1,326

Issuances	(165)	(1,313)
Settlements[1]	(14,443)	(27,686)
Balance at end of period	$7,512	$24,418
The amount of total losses for the period included in earnings attributable to the change in the mark to market of commodity derivatives contracts still held at December 31, 2016 and 2015	$(13,622)	$(1,890)

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

At December 31, 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 December 31, 2016 was $403.1 million based on quoted market prices of the Notes (Level 1) and the respective carrying value of the Revolving Credit Facility because the interest rate approximated the current market rate (Level 2). The estimated fair value of the Company’s long-term debt at December 31, 2015 was $377.5 million based on quoted market prices of the Notes (Level 1) and the respective carrying value of the Revolving Credit Facility because the interest rate approximated the current market rate (Level 2).

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

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The fair value guidance, as amended, establishes that every derivative instrument is to be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 7, "Derivative Instruments and Hedging Activity."

7. Derivative Instruments and Hedging Activity

The Company maintains a commodity price risk management strategy that uses derivative instruments to minimize significant, unanticipated earnings fluctuations that may arise from volatility in commodity prices. The Company uses costless collars, index, basis and fixed price swaps and put and call options to hedge oil, condensate, natural gas and NGLs price risk.

All derivative contracts are carried at their fair value on the balance sheet and all changes in value are recorded in the consolidated statement of operations in gain (loss) on commodity derivatives contracts. For the years ended December 31, 2016 and 2015, the Company reported losses of $13.6 million and $1.9 million, respectively, in the consolidated statement of operations related to the change in the fair value of its commodity derivative instruments. For the year ended December 31, 2014, the Company reported a gain of $23.9 million in the consolidated statement of operations related to the change in the fair value of its commodity derivative instruments.

As of December 31, 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)
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	$—	$—	$—
2017[2]	Fixed price swap	275	49,775	$51.25	$—	$—	$—
2018[5]	Put spread	425	103,275	$—	$80.00	$60.00	$—

(1) Crude volumes hedged include oil, condensate and certain components of the Company's 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.

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As of December 31, 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	Total of Notional Volume	Base Fixed Price	Floor (Long)	Short Put	Ceiling (Short)
		(in MMBtu's)					
2017	Costless three-way collar	5,000	1,825,000	$—	$ 3.00	$2.35	$ 4.00
2017(1)	Costless collar	2,000	180,000	$—	$ 3.10	$—	$ 3.78
2017(2)	Fixed price swap	1,500	321,000	$3.30	$ —	$—	$ —
2018	Costless three-way collar	5,000	1,825,000	$—	$ 3.00	$2.35	$ 4.00

(1) For the period January to March 2017.
(2) For the period April to October 2017.

As of December 31, 2016, all of the Company's economic derivative hedge positions were with a multinational energy company or large financial institution, which are not known to the Company to be in default on their derivative positions. The Company is exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate non-performance by such counterparties. None of the Company's derivative instruments contains credit-risk related contingent features.

In conjunction with certain derivative hedging activity, the Company deferred the payment of certain put premiums for the production month period January 2017 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:

	For the Years Ended December 31, 2016	2015
	(in thousands)	
Current commodity derivative premium put payable	$ 1,654	$ 3,194
Long-term commodity derivative premium payable	969	2,788
Total unamortized put premium liabilities	$ 2,623	$ 5,982

For the Years Ended December 31,

	2016	2015
	(in thousands)	
Put premium liabilities, beginning balance	$5,982	$7,183
Settlement of put premium liabilities	(3,194)	(2,295)
Additional put premium liabilities	(165)	1,094
Put premium liabilities, ending balance	$2,623	$5,982

The following table provides information regarding the amortization of the deferred put premium liabilities by year as of December 31, 2016:

	Amortization (in thousands)
January to December 2017	$ 1,654
January to December 2018	969
Total unamortized put premium liabilities	$ 2,623

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Additional Disclosures about Derivative Instruments and Hedging Activities

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

	Fair Values of Derivative Instruments		
	Derivative Assets (Liabilities)		
		Fair Value December 31,	
	Balance Sheet Location	2016	2015
		(in thousands)	
Derivatives not designated as hedging instruments			
Commodity derivative contracts	Current assets	$ 6,212	$ 15,534
Commodity derivative contracts	Other assets	1,638	9,335
Commodity derivative contracts	Current liabilities	(338)	—
Commodity derivative contracts	Long-term liabilities	—	(451)
Total derivatives not designated as hedging instruments		$ 7,512	$ 24,418

	Location of (Loss) Gain Recognized in Income on Derivatives	Amount of (Loss) Gain Recognized in Income on Derivatives For the Years Ended December 31, 2016	2015	2014
		(in thousands)		
Derivatives not designated as hedging instruments				
Commodity derivative contracts	(Loss) gain on commodity derivatives contracts	$(2,863)	$24,589	$19,569
Total		$(2,863)	$24,589	$19,569

8. Capital Stock

Common Stock

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

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

On May 7, 2015, the Company entered into the ATM Program. The shares were issued pursuant to the Company's then-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. During the year ended December 31, 2016, 18,606,943 shares were sold through the ATM program for net proceeds of $24.4 million. For the period January 1, 2017 to February 20, 2017, the Company sold 5,447,919 shares through the ATM program for net proceeds of $8.3 million. The ATM Program expired on February 24, 2017.

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 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.

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On February 16, 2017, the Company entered into the Purchase Agreement with purchasers affiliated with Ares, pursuant to which the Company will issue and sell for cash to the Purchasers (i) $125,000,000 aggregate principal amount of its Convertible Notes due 2022 sold at par, which Convertible Notes, subject to the receipt of approval of the Company's stockholders, will be convertible into Common Stock, par value $0.001 per share of the Company or, in certain circumstances, cash in lieu of Common Stock or a combination thereof as described below and (ii) 29,408,305 shares of Common Stock for a purchase price of $50.0 million. The Common Stock was priced based on a 30-trading day VWAP determined on the date immediately prior to the signing date of the Purchase Agreement. The 30-day VWAP as of February 15, 2017 was $1.7002, which resulted in the agreement to issue 29,408,305 shares of Common Stock to the Purchasers, or approximately 18.8% of the shares of the Company's 156,715,833 shares of Common Stock issued and outstanding as of January 31, 2017.

Stockholder Rights Agreement

On January 18, 2016, the Company's board of directors adopted the 2016 Rights Agreement pursuant to which the Company declared a dividend of one 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 entitled the holder, subject to the terms of the 2016 Rights Agreement, to purchase one one-thousandth of a share of the Company's Series C Preferred Stock at a price of $6.96, subject to certain adjustments. The purpose of the 2016 Rights Agreement was 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 2016 Rights Agreement expired on January 18, 2017.

On January 27, 2017, the Company's board of directors adopted the 2017 Rights Agreement pursuant to which the Company declared a dividend of one Right for each of the Company's issued and outstanding shares of common stock. The dividend was paid to stockholders of record on February 10, 2017. Each Right entitles the holder, subject to the terms of the 2017 Rights Agreement, to purchase one one-thousandth of a share of Series C Preferred Stock at a price of $10.74, subject to certain adjustments. The purpose of the 2017 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 4.95% 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 prior to the earliest of (i) January 27, 2020 or such later day as may be established by the Board prior to the expiration of the Rights, provided that the extension is submitted to the Company's stockholders for ratification at the next annual meeting of stockholders of the Company succeeding such extension; (ii) the time at which the Rights are redeemed pursuant to the 2017 Rights Agreement; (iii) the time at which the Rights are exchanged pursuant to the 2017 Rights Agreement; (iv) the time at which the Rights are terminated upon the occurrence of certain transactions; (v) the close of business on the first day after the Company’s 2017 annual meeting of stockholders, if approval by the stockholders of the Company of the 2017 Rights Agreement has not been obtained at such meeting; (vi) the close of business on the effective date of the repeal of Section 382 of the Tax Code, if the Board determines that the 2017 Rights Agreement is no longer necessary or desirable for the preservation of Tax Benefits; and (vii) the close of business on the first day of a taxable year of the Company to which the Board determines that no Tax Benefits are available to be carried forward.

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

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 December 31, 2016, there were 4,045,000 shares of Series A Preferred Stock issued and outstanding with a $25.00 per share liquidation preference.

The Series A Preferred Stock ranks senior 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.

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. Pursuant to Amendment No. 10 to the Company's Revolving Credit Facility, on January 10, 2017, the Company declared a special cash dividend on the Series A Preferred Stock to pay in full all accumulated and unpaid cash dividends accrued since April 1, 2016 at an annualized 8.625% through the payment date. The Series A Preferred Stock January 2017 dividend was payable on January 31, 2017 to holders of record at the close of business on January 20, 2017.

Under Amendment No. 10 to the Company's Revolving Credit Facility, payment of the declared Series A Preferred Stock January 2017 dividend and monthly preferred stock cash dividends through May 2017 are permitted contingent upon the satisfaction of certain conditions, including but not limited to, (i) the absences of any defaults or borrowing base deficiency, (ii) for any dividends declared and paid in respect of April 2017 and May 2017, having cash liquidity (including any available borrowings under the Revolving Credit Facility) of more than $30.0 million and (iii) paying any permitted dividends solely from proceeds received by the Company from sales of equity since November 30, 2016 (including through the ATM Program).

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 years ended December 31, 2016, 2015 and 2014, the Company recognized dividends of $8.7 million, $8.7 million and $8.7 million, respectively, for the Series A Preferred Stock. As of December 31, 2016, accumulated and unpaid dividends on the outstanding Series A Preferred Stock aggregated to $6.5 million, or $1.6171875 per share. The accumulated and unpaid Series A Preferred Stock dividends were declared on January 10, 2017 and paid to holders of record on January 31, 2017.

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Series B Preferred Stock

At December 31, 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 Company’s common stock and on parity with Series A Preferred Stock with respect to the payment of dividends and distribution of assets upon liquidation, dissolution or winding up. The Series B Preferred Stock are subordinated to all of the Company’s existing and future debt and all future capital stock designated as senior to the Series B Preferred Stock.

Except upon a change in ownership or control, the Series B Preferred Stock may not be redeemed before November 15, 2018, at or after which time it may be redeemed at the Company’s option for $25.00 per share in cash. Following a change in 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. Pursuant to Amendment No. 10 to the Company’s Revolving Credit Facility, on January 10, 2017, the Company declared a special cash dividend on the Series B Preferred Stock to pay in full all accumulated and unpaid cash dividends accrued since April 1, 2016 at an annualized 10.75% through the payment date. The Series B Preferred Stock January 2017 dividend was payable on January 31, 2017 to holders of record at the close of business on January 20, 2017.

Under Amendment No. 10 to the Company’s Revolving Credit Facility, payment of the declared Series B Preferred Stock January 2017 dividend and monthly preferred stock cash dividends through May 2017 are permitted contingent upon the satisfaction of certain conditions, including but not limited to, (i) the absences of any defaults or borrowing base deficiency, (ii) for any dividends declared and paid in respect of April 2017 and May 2017, having cash liquidity (including any available borrowings under the Revolving Credit Facility) of more than $30.0 million and (iii) paying any permitted dividends solely from proceeds received by the Company from sales of equity since November 30, 2016 (including through the ATM Program).

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 years ended December 31, 2016, 2015 and 2014, the Company recognized dividends of $5.8 million, $5.8 million and $5.8 million, respectively, for the Series B Preferred Stock. As of December 31, 2016, accumulated and unpaid dividends on the outstanding Series B Preferred Stock aggregated to $4.3 million, or $2.0158686 per share. The accumulated and unpaid Series B Preferred Stock dividends were declared on January 10, 2017 and paid to holders of record on January 31, 2017.

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Other Share Issuances

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

	For the Years Ended December 31, 2016	2015
Other stock issuances:		
Shares of restricted common stock granted	1,764,645	1,426,604
Shares of restricted common stock vested	1,487,269	1,422,670
Shares of common stock issued pursuant to PBUs vested, net of forfeitures of 207,891 shares and 212,858 shares, respectively	502,593	497,636
Shares of restricted common stock surrendered upon vesting/exercise[(1)]	392,094	413,333
Shares of restricted common stock forfeited	128,435	119,499

(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.

In connection with the merger, Parent’s 2006 Long-Term Stock Incentive Plan was assumed by Gastar Exploration Inc. and, effective as of the merger, was amended, restated and renamed the “Gastar Exploration Inc. Long-Term Incentive Plan” (as amended, the “LTIP”).

Shares Reserved

At December 31, 2016, the Company had 214,600 shares of common stock reserved for the exercise of stock options and 1,475,730 shares reserved for the settlement of PBUs.

9. Equity Compensation Plans

Share-Based Compensation Plan

The vesting period for recent restricted common stock grants has been one year for directors and three years for employees, vesting annually from the date of grant in equal proportions.

On June 12, 2014, the Company’s stockholders approved the LTIP. The approved amendment to the LTIP, effective April 24, 2014, among other things, increased the number of shares reserved for issuance under the LTIP by 3,000,000 shares. The LTIP permits us to issue stock options, stock appreciation rights, bonus stock awards and any other type of award (including PBUs, which are consistent with the LTIP’s purpose to directors, officers and employees of the Company and its subsidiaries.

At December 31, 2016, 1,590,327 shares of common stock were available for future stock-based compensation grants under the LTIP. All shares of common stock issued upon the exercise of stock option grants or vesting of restricted stock grants and PBUs are authorized, issued by the Company and are fully paid and non-assessable.

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Stock Options

There were no stock options granted during the years ended December 31, 2016, 2015 and 2014. However, in prior years, the Company issued stock options as a component of its equity compensation program and the fair value of such stock options grants were estimated using the Black-Scholes Merton valuation model. As of December 31, 2016, all stock options were vested.

The following tables summarize certain information related to outstanding stock options under the LTIP as of and for the year ended December 31, 2016:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2015	866,600	$ 11.75		
Granted	—	—		
Exercised	—	—		
Canceled/Expired	(571,000)	14.77		
Forfeited	(81,000)	8.75		
Outstanding at December 31, 2016	214,600	$ 4.87		
Options vested and exercisable at December 31, 2016	214,600	$ 4.87	1.98	$ —

There was no unrecognized expense as of December 31, 2016 for all outstanding options.

Restricted Shares

The Company has granted restricted shares of common stock which vest based upon continued service or certain other events. The vesting period for recent restricted common stock grants has been from one to three years, but generally has been over three years, except for grants to Company directors that vest in one year, vesting annually from the date of grant in equal proportions. The following table summarizes information related to restricted shares at December 31, 2016:

	Shares	Weighted Average Fair Value	Weighted Average Remaining	Aggregate Intrinsic Value

		per Share	Contractual Term (in years)	(in thousands)
Outstanding non-vested restricted shares at December 31, 2015	2,296,349	$ 2.63		
Granted	1,764,645	1.19		
Vested	(1,487,269)	2.37		
Forfeited	(128,435)	1.88		
Outstanding non-vested restricted shares at December 31, 2016	2,445,290	$ 1.79	1.49	$ 3,790

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands, except per share data)		
Weighted average grant date fair value per restricted share	$1.19	$2.40	$5.85
Total fair value of restricted shares vested	$3,530	$3,794	$3,497

For the year ended December 31, 2016, the Company recognized $2.7 million of compensation expense associated with restricted share awards. Unrecognized compensation expense as of December 31, 2016 for all outstanding restricted share awards is $1.1 million and will be recognized over a weighted average period of 1.33 years.

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Performance Based Units

Commencing 2013, a portion of long-term incentive grants to Company management were in the form of PBUs. The PBUs represent a contractual right to receive shares of the Company's common stock, an amount of cash equal to the fair market value of a share of the Company's common stock, or a combination of shares of the Company's common stock and cash as of the date of settlement based on the number of PBUs to be settled. The settlement of PBUs may range from 0% to 200% of the targeted number of PBUs stated in the agreement contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PBUs granted prior to 2015 vest equally and settlement is determined annually over a three-year period. The PBUs granted in 2015 and 2016 cliff vest at the end of a three-year period. Any PBUs not vested at each measurement date will expire.

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

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

	PBUs	Weighted Average Fair Value per Unit
Unvested PBUs at December 31, 2015	1,283,167	$ 3.24
Granted	801,397	1.62
Vested	(448,634)	2.76
Forfeited	(160,200)	3.40
Unvested PBUs at December 31, 2016	1,475,730	$ 2.49

For the year ended December 31, 2016, the Company recognized $1.2 million of compensation expense associated with the PBUs. As of December 31, 2016, the Company had $1.6 million of total unrecognized expense for the PBUs to be recognized over a weighted average period of 1.65 years.

Stock-Based Compensation Expense

For the years ended December 31, 2016, 2015 and 2014, the Company recorded stock-based compensation expense for restricted shares, PBUs, and stock options granted using the fair-value method of $3.9 million, $5.0 million and $4.9 million, respectively. All stock-based compensation costs were expensed and not tax affected, as the Company currently records no U.S. income tax expense.

As of December 31, 2016, the Company had approximately $2.7 million of total unrecognized compensation cost related to unvested restricted shares and PBUs, which is expected to be amortized over the following periods:

	Amount (in thousands)
2017	$ 1,913
2018	717
2019	56
Total	$ 2,686

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10. Interest Expense

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands)		
Interest expense:			
Cash and accrued	$33,368	$30,981	$28,851
Amortization of deferred financing costs(1)	4,980	3,584	3,067
Capitalized interest	(3,102)	(3,879)	(4,347)
Total interest expense	$35,246	$30,686	$27,571

(1)The years ended December 31, 2016, 2015 and 2014 include $2.8 million, $2.5 million and $2.3 million, respectively, of debt discount accretion related to the Notes.

11. Income Taxes

The following table summarizes the components of the Company's (loss) income before income taxes for the periods indicated:

	For the Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
United States	$(89,061)	$(459,507)	$50,953
Total income (loss) before income taxes	$(89,061)	$(459,507)	$50,953

The Company did not report any current provision for income taxes for the years ended December 31, 2016, 2015 and 2014.

The Company had no deferred income tax expense (benefit) for the years ended December 31, 2016, 2015 and 2014.

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands)		
Expected income tax provision (benefit) at statutory rate	$(31,172)	$(160,827)	$17,833
State tax, tax effected	(1,408)	(7,799)	803
Stock-based compensation expense (benefit)	1,995	255	(1,291)
Non-deductible compensation	178	—	—
Other	693	17	38
Other changes in valuation allowance	29,714	168,354	(17,383)
Actual income tax provision	$—	$—	$—

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

	As of December 31,	
	2016	2015
	(in thousands)	
Deferred tax asset (liability):		
Capital assets	$33,131	$10,485
Stock-based compensation	2,499	4,243
Net operating loss carry forwards	196,775	187,963
Foreign tax credit carry forwards	50,681	50,681
Valuation allowance	(283,086)	(253,372)
Net deferred tax asset	$—	$—

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The Company has approximately $536.2 million of net operating loss carry forwards as of December 31, 2016, which, if not utilized, will expire between 2030 and 2036. For U.S. federal income tax purposes, as of December 31, 2016, the Company has foreign tax credit carry forwards of $50.7 million, which, if not utilized, will expire in 2019. The utilization of the net operating loss carry forward and the foreign tax credit carry forward are dependent on the Company generating future taxable income and U.S. tax liability, as well as other factors.

Current authoritative guidance requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For a tax position meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. At December 31, 2016, the Company did not have any material unrecognized tax benefits that, if recognized, would affect the effective tax rate.

The Company is subject to examination of income tax filings in the U.S. and various state jurisdictions for the periods 2010 and forward and the foreign jurisdiction of Canada for the tax periods 2000 through 2013 due to the Company's continued loss position in such jurisdiction.

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

12. Earnings per Share

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands, except per share and share data)		
Net (loss) income attributable to common stockholders	$(103,534)	$(473,980)	$36,529
Weighted average shares of common stock outstanding - basic	111,367,452	77,511,677	63,270,733
Incremental shares from unvested restricted shares	—	—	2,451,903
Incremental shares from outstanding stock options	—	—	97,491
Incremental shares from outstanding PBUs	—	—	672,462
Weighted average shares of common stock	111,367,452	77,511,677	66,492,589

outstanding - diluted			
Net (loss) income per share of common stock attributable to common stockholders:			
Basic	$(0.93)	$(6.11)	$0.58
Diluted	$(0.93)	$(6.11)	$0.55
Shares of common stock excluded from denominator as anti-dilutive:			
Unvested restricted shares	438,948	177,663	34,058
Unvested PBUs	487,995	17,589	—
Total	926,943	195,252	34,058

13. Commitments and Contingencies

Contractual Obligations

The Company leases its office facilities and certain office equipment under non-cancelable operating lease agreements with various termination dates, the latest of which is April 2022. For the years ended December 31, 2016, 2015 and 2014, office lease expense totaled approximately $524,000, $687,000 and $649,000, respectively.

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As of December 31, 2016, the Company’s aggregate future minimum annual rental commitments under the non-cancelable leases for the next five years are as follows:

2017	$447
2018	733
2019	617
2020	620
2021 and thereafter	834
	$3,251

Litigation

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.

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. 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 for the year ended December 31, 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 or contract 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.

Gastar Exploration USA, Inc., et al v. Williams Ohio Valley Midstream LLC (American Arbitration Association Matter No. 70-198-Y-00461-13). On July 16, 2013, Gastar USA and two similarly situated co-claimants initiated an arbitration proceeding against Williams Ohio Valley Midstream LLC ("Williams OVM"). The claimants allege that Williams OVM has breached various agreements relating to the gathering, processing and marketing of natural gas, NGLs and condensate produced from properties that are owned in part by Gastar USA in the Marcellus Shale in Marshall and Wetzel Counties, West Virginia, and requested that an Arbitration Panel assess an unspecified amount of damages against Williams OVM for, among other claims, failure to timely construct certain gathering and processing facilities and maximize the net value of the condensate and NGLs produced as provided in the agreements.
On August 7, 2013, Williams OVM filed an answering statement and counterclaim for damages in excess of $612,000 in the arbitration matter. On December 31, 2013, the parties informed the Arbitration Panel that they had reached an agreement in

principle to settle their disputes. The disputes were subsequently settled, on a confidential basis, between both parties on June 17, 2014. Although there were some changes to the contracts, there were no changes to existing contractual fees. After production taxes and lease operating expense reimbursement benefit, the net arbitration settlement amount received by Gastar USA was approximately $8.6 million.

The Company has been expensing legal defense costs on these proceedings as they are incurred.

The Company is party to various legal proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Net of available insurance and performance of contractual defense and indemnity obligations, where applicable, management does not believe any such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

Commitments

Gas Purchase Agreement

During December 2010, the Company, along with Atinum, entered into a gas purchase agreement with SEI Energy, LLC ("SEI") with respect to its Marshall County, West Virginia production. The initial term of the gas purchase agreement was five years with the option to extend the term of the gas purchase agreement for an additional five year period. The Company's Marshall County, West Virginia production was dedicated to SEI for the term of the gas purchase agreement. During June 2014, the Company entered into an agreement to include the dedication of all of its Wetzel County, West Virginia production to SEI in addition to its Marshall County, West Virginia production. Under such agreement, SEI would purchase all hydrocarbon production, including all natural gas, condensate and natural gas liquids. Upon closing of the Appalachian Basin Sale, the Company has no further obligations under the SEI agreement.

SEI filed for Chapter 7 bankruptcy on June 3, 2016. As such, the Company determined that a receivable account from SEI would no longer be collectible.

Drilling Program

Upon completion of a Drilling Program tranche, the Investor has the right, but not the obligation, for a period of six months to cause the Company to purchase the Investor's WI Tail interest in the Drilling Program that is not subject to final reversion for such tranche for fair market value by applying the methodology to determine a 15% discounted present value as defined by the Development Agreement. If the Investor fails to exercise the Investor Put Right within the six-month period after achieving final reversion, then for a period of six months thereafter, the Company shall have the right, but not the obligation, to purchase the WI Tail from the Investor on the same fair market value approach of the Investor Put Right. If final reversion has not been achieved by the eighth anniversary of the spud date of the first well in a given tranche, Investor will, for a period of six months thereafter, have the right to cause us to by Investor's then-current interest in such tranche at an agreed upon valuation.

Restoration, Removal and Environmental Liabilities

The Company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated future removal and site restoration costs. These costs are initially measured at a fair value and are recognized in the consolidated financial statements as the present value of expected future cash flows. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement obligation cost are recognized in the results of operations. Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded mainly from the Company’s cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any quarter or year.

At December 31, 2016, the Company had total liabilities of $5.5 million related to asset retirement obligations of which $89,000 is recorded as short-term liabilities and $5.4 million is recorded as long-term liabilities. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. See Note 5, “Asset Retirement Obligation.”

Indemnifications

Indemnifications in the ordinary course of business have been provided pursuant to provisions of purchase and sale contracts, service agreements, joint venture agreements, operating agreements and leasing agreements. In these agreements, the Company may indemnify counterparties if certain events occur. These indemnification provisions vary on an agreement by agreement basis. In some

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cases, there are no pre-determined amounts or limits included in the indemnification provisions and the occurrence of contingent events that will trigger payment, if any, is difficult to predict.

Employment Agreements

The Company entered into employment agreements with its Chief Executive Officer and its Chief Financial Officer, effective February 24, 2005 (as amended July 25, 2008 and February 3, 2011) and May 17, 2005 (as amended July 25, 2008 and April 10, 2012), respectively. The agreements set forth, among other things, annual compensation, and adjustments thereto, bonus payments, fringe benefits, termination and severance provisions.

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

14. Concentration of Risk and Significant Customers

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

	For the Years Ended December 31,		
	2016	2015	2014
Appalachian Basin	5 %	17 %	39 %
Mid-Continent	95 %	83 %	61 %

The following table provides information regarding the Company's significant customers whom accounted for more than 10% of the Company's oil, condensate, natural gas and NGLs revenues, excluding hedge impact, for the periods indicated:

	For the Years Ended December 31,		
	2016	2015	2014
Sunoco	67 %	62 %	37 %
Superior	12 %	6 %	5 %
SEI(1)	5 %	22 %	50 %

(1) SEI filed for Chapter 7 bankruptcy on June 3, 2016.

Sunoco Logistics Partners L.P. (“Sunoco”) purchases the majority of the Company’s Mid-Continent oil production. Superior Pipeline Company (“Superior”) purchases the majority of the Company’s Mid-Continent natural gas and NGLs production. There are numerous purchase and transportation alternatives currently available in the Mid-Continent so in the event that Sunoco were to cease purchasing and transporting our oil and condensate production and/or Superior were to cease purchasing and transporting our natural gas and NGLs production, the Company’s ability to conduct normal operations would not be significantly restricted. Prior to the Appalachian Basin Sale, SEI purchased the majority of the Company’s Appalachian Basin production.

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15. Statement of Cash Flows – Supplemental Information

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands)		
Cash paid for interest, net of capitalized amounts	$30,480	$26,859	$24,632
Non-cash transactions:			
Capital expenditures (excluded from) included in accounts payable and accrued drilling costs	$(82)	$(26,228)	$12,777
Capital expenditures included in accounts receivable	409	—	4,077
Asset retirement obligation included in oil and natural gas properties	432	526	221
Asset retirement obligation for property disposals	(1,045)	(416)	(645)
Application of advances to operators	(347)	11,445	58,326
Other	—	5	(11)

16. Quarterly Consolidated Financial Data – Unaudited

The following tables summarize the Company’s results of operations by quarter for the years ended December 31, 2016 and 2015:

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$14,811	$12,153	$13,003	$18,287
(Loss) income from operations[1]	(60,592)	(5,142)	7,959	3,929
Loss before provision for income taxes	(69,857)	(14,481)	(178)	(4,545)
Net loss	(69,857)	(14,481)	(178)	(4,545)
Dividends on preferred stock	3,618	3,619	3,618	3,618
Net loss attributable to common stockholders	(73,475)	(18,100)	(3,796)	(8,163)
Net loss per share of common stock attributable to				

common stockholders:				
Basic	$(0.93)	$(0.17)	$(0.03)	$(0.06)
Diluted	$(0.93)	$(0.17)	$(0.03)	$(0.06)
Weighted average shares of common stock outstanding:				
Basic	78,788,133	104,009,337	129,301,817	132,936,419
Diluted	78,788,133	104,009,337	129,301,817	132,936,419

(1)(Loss) income from operations for the first quarter includes impairment of oil and natural gas properties of $48.5 million the third quarter income from operations includes $10.1 million of litigation settlement benefit.

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	2015 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share and per share data)			
Revenues	$34,372	$21,928	$28,386	$22,608
Income (loss) from operations[(1)]	8,172	(107,462)	(180,272)	(149,272)
Income (loss) before provision for income taxes	614	(114,395)	(188,201)	(157,525)
Net income (loss)	614	(114,395)	(188,201)	(157,525)
Dividends on preferred stock	3,618	3,619	3,618	3,618
Net loss attributable to common stockholders	(3,004)	(118,014)	(191,819)	(161,143)
Net loss per share of common stock attributable to common stockholders:				
Basic	$(0.04)	$(1.52)	$(2.47)	$(2.07)
Diluted	$(0.04)	$(1.52)	$(2.47)	$(2.07)
Weighted average shares of common stock outstanding:				
Basic	77,114,826	77,611,167	77,628,120	77,685,049
Diluted	77,114,826	77,611,167	77,628,120	77,685,049

(1) Income (loss) from operations for the second, third and fourth quarters include impairment of oil and natural gas properties of $100.2 million, $182.0 million and $144.8 million, respectively.

17. Supplemental Oil and Gas Disclosures – Unaudited

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table presents the Company’s aggregate capitalized costs relating to oil and natural gas producing activities in the U.S. for the periods indicated:

	As of December 31, 2016	2015	2014
	(in thousands)		
Proved properties	$1,253,061	$1,286,373	$1,124,367
Unproved properties	67,333	92,609	128,274
Total oil and natural gas properties	1,320,394	1,378,982	1,252,641
Less:			
Impairment of proved oil and natural gas properties	(813,314)	(764,817)	(337,939)
Accumulated depreciation, depletion and amortization	(315,373)	(286,020)	(223,555)

Net capitalized costs	$191,707	$328,145	$691,147

Pursuant to authoritative guidance for accounting for asset retirement obligations, net capitalized costs include related asset retirement costs of approximately $1.5 million, $2.4 million and $2.4 million at December 31, 2016, 2015 and 2014, respectively.

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

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

	For the Years Ended December 31,		
	2016	2015	2014
	(in thousands)		
Property acquisition			
Proved	$570	$15,615	$—
Unproved	38,941	50,434	41,475
Exploration	19,761	53,290	127,384
Development	3,810	54,316	57,913
Total costs incurred	$63,082	$173,655	$226,772

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Results of Operations for Oil and Natural Gas Producing Activities

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

	For the Year Ended December 31,		
	2016	2015	2014
	(in thousands, except per Mcfe data)		
Oil, condensate, natural gas and NGLs sales, including commodity derivatives	$58,254	$107,294	$171,418
Production expenses	(24,217)	(28,792)	(29,735)
Impairment of oil and natural gas properties	(48,497)	(426,878)	—
Depreciation, depletion and amortization	(29,353)	(62,465)	(45,765)
Results of producing activities	$(43,813)	$(410,841)	$95,918
Depreciation, depletion and amortization per MBoe	$10.23	$12.67	$12.34

The results of producing activities exclude interest charges and general corporate expenses.

In accordance with current authoritative guidance, estimates of the Company’s proved reserves and future net revenues are made using benchmark prices, before lease adjustments, that are the 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas as of December 31, 2016 and 2015. The following table provides the key benchmark natural gas and oil prices used as of the periods indicated to calculate reserves:

	As of December 31,	
	2016	2015
Natural gas (per MMBtu):		
Henry Hub	$2.48	$2.59
Oil (per Bbl):		
WTI spot	$42.75	$50.28

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

Net Proved and Proved Developed Reserve Summary

Reserve Estimation. The reserve information presented below is based on estimates of net proved reserves as of December 31, 2016, 2015, and 2014. Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and governmental regulations (i.e., prices and costs as of the date the estimate is made). Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productivity at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. The Company's proved developed and proved undeveloped reserves are located only in the U.S.

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The following tables set forth changes in estimated net proved and proved developed and undeveloped reserves for the years ended December 31, 2016, 2015 and 2014:

Change in Proved Reserves	Condensate and Oil (MBbl) (1)	Natural Gas (MMcf) (2)	NGLs (MBbl) (1)	MBoe Equivalents (3)
Proved reserves as of December 31, 2013	14,718	180,710	9,798	54,634
2014 Activity:				
Extensions and discoveries[4]	13,137	121,672	9,394	42,810
Revisions of previous estimates	1,780	(2,465)	7,205	8,574
Production	(975)	(11,598)	(800)	(3,708)
Sales in place	(24)	(1,314)	(4)	(247)
Proved reserves as of December 31, 2014	28,636	287,005	25,593	102,063
2015 Activity:				
Extensions and discoveries[5]	4,777	14,114	2,244	9,374
Revisions of previous estimates[6]	(8,962)	(182,600)	(13,873)	(53,268)
Production	(1,425)	(13,759)	(1,212)	(4,931)
Purchases in place	1,270	4,965	873	2,971
Sales in place	(94)	(1,274)	(26)	(332)
Proved reserves as of December 31, 2015	24,202	108,451	13,599	55,877
2016 Activity:				
Extensions and discoveries	1,582	7,213	898	3,681
Revisions of previous estimates[7]	(9,890)	(17,825)	(3,317)	(16,177)
Production	(1,105)	(6,145)	(739)	(2,869)
Sales in place	(1,033)	(53,841)	(4,929)	(14,935)
Proved reserves as of December 31, 2016	13,756	37,853	5,512	25,577

(1) Thousand barrels
(2) Million cubic feet or million cubic feet equivalent, as applicable
(3) Thousand barrels of oil, condensate or NGLs and natural gas equivalent. Natural gas volumes have been converted to equivalent oil, condensate and NGLs volumes using a conversion factor of one barrel of oil, condensate or NGLs to six cubic feet of natural gas.
(4) Of the 2014 extensions and discoveries, 69% resulted from successful drilling results in the Marcellus Shale. The remainder of the 2014 extensions and discoveries resulted from the Company's Mid-Continent drilling operations.
(5) All of the 2015 extensions and discoveries resulted from the Company’s Mid-Continent drilling operations.
(6) The 2015 revisions of previous estimates resulted primarily from a 36.8 MMBoe decrease in Appalachian Basin reserves due to the suspension of the Marcellus and Utica Shale drilling programs in 2015 and the significant decrease in the 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas as of December 31, 2015 and 2014.
(7) The 2016 revisions of previous estimates resulted primarily from the removal of Hunton PUD locations as the Company now focuses its capital activity on drilling Meramec and Osage wells to hold acreage by production and delineate its STACK Play position.

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Proved Developed and Undeveloped Reserves	Condensate and Oil (MBbl) (1)	Natural Gas (MMcf) (2)	NGLs (MBbl) (1)	MBoe Equivalents (3)
December 31, 2014				
Proved developed reserves	6,968	114,564	10,726	36,789
Proved undeveloped reserves	21,668	172,441	14,867	65,274
Total	28,636	287,005	25,593	102,063
December 31, 2015				
Proved developed reserves	7,181	77,966	8,240	28,415
Proved undeveloped reserves	17,021	30,485	5,359	27,462
Total	24,202	108,451	13,599	55,877
December 31, 2016				
Proved developed reserves	6,037	22,786	3,181	13,015
Proved undeveloped reserves	7,719	15,067	2,332	12,562
Total	13,756	37,853	5,512	25,577

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

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

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

For the years ended December 31, 2016, 2015 and 2014 future cash inflows were computed using the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil (the "benchmark base prices"). For the periods indicated, the following benchmark base prices for natural gas and oil, before lease adjustments, were used in the calculations:

	For the Years Ended December 31,		
	2016	2015	2014
Natural gas, per MMBtu			
Henry Hub	$2.48	$2.59	$4.35
Oil, per barrel:			
WTI spot	$42.75	$50.28	$94.99

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

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

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

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

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

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

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves in the U.S. is presented below (in thousands):