EMTEC INC/NJ
Form 8-K
February 05, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 2, 2009

EMTEC, INC.
(Exact Name of Registrant as Specified in its Charter)

Delaware	0-32789	87-0273300
(State or other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

525 Lincoln Drive 5 Greentree Center, Suite 117 Marlton, NJ	08054
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code: (856) 552-4204

(Former name or former address, if changed from last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 5.02(e) Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

At our Annual Meeting on February 2, 2009, the stockholders approved an amendment to the Emtec, Inc. 2006 Stock-Based Incentive Compensation Plan (the "Plan"), to increase the aggregate number of shares of Common Stock available for awards under the Plan from 1,400,000 shares to 2,543,207 shares.

SIGNATURE

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

	Emtec, Inc. (Registrant)	
Date: February 5, 2009	By:	/s/ Stephen C. Donnelly Chief Financial Officer

y sending the Company formal notices of breach. Under the leases, these plaintiffs can file suit if the alleged breaches have not been cured within 60 days.

Eagle Natrium LLC v. Gastar Exploration USA, Inc., Cause No. GD-14-7208, In the Court of Common Pleas of Allegheny County, Pennsylvania. On April 22, 2014, Eagle Natrium LLC (“Eagle”), a wholly-owned subsidiary of Axiall Corporation, filed a complaint against the Company in the Court of Common Pleas of Allegheny County, Pennsylvania seeking to enjoin Gastar’s hydraulic fracturing and completion operations on three wells drilled from Gastar’s Goudy pad in Marshall County, West Virginia, or conducting any activity that poses a substantial risk of harm to Eagle’s brine operations. Gastar was the operator of approximately 16,000 acres in Marshall County, West Virginia, including a 3,300 gross acre oil and gas lease adjacent to Eagle’s facilities. Eagle asserted its right to relief based on certain of the lessor’s rights which were assigned to Eagle by the lessor solely as they relate to the brine and related facilities. A hearing on the request for preliminary injunction was held in the summer of 2014. After considering the evidence presented at the hearing and the party’s briefing, the court issued an order on October 21, 2014 denying the request for a preliminary injunction. In January 2015, Gastar began completion operations and has since completed the three wells drilled from its Goudy pad that formed the basis of Eagle’s complaint. In 2016, the Company amended its answer and has added counterclaims seeking damages from Eagle as a result of the proceedings. Specifically, Gastar has asserted a breach of contract claim, seeking damages for lost revenues, rig up and rig down costs and attorney’s fees relating to the Pennsylvania lawsuit filed by Eagle. Eagle has also maintained its breach of contract claim against the Company. The Court has bifurcated the proceeding into a separate liability and damages phase. On June 25, 2018, the Court commenced a six-day bench trial on liability. A decision on the parties' respective liability remains pending.

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

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

14. Statement of Cash Flows – Supplemental Information

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

	For the Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Cash paid for interest, net of capitalized amounts	$77	$17,361
Non-cash transactions:		
Capital expenditures included in accounts payable and accrued drilling costs	$(6,716)	$8,820
Capital expenditures included in accounts receivable	$—	$76
Capital expenditures excluded from prepaid expenses	$(88)	$—
Asset retirement obligation included in oil and natural gas properties	$74	$289
Asset retirement obligation sold	$(2,581)	$(1,533)
Application of advances to operators	$18	$49
Non-cash financing charges excluded from accounts payable and accrued liabilities	$—	$501
Conversion of convertible debt to equity	$—	$37,500

15. Subsequent Events

Pursuant to Amendment No. 2 to the Term Loan, on July 2, 2018, the Company elected to pay in kind 100% of the interest due for the period April 2, 2018 to July 2, 2018 in the amount of $6.9 million, thus increasing the outstanding principal balance of the Term Loan to $276.8 million at such time.

On July 20, 2018, in an amendment to the Schedule 13D filed by Ares, Ares delivered a non-binding preliminary term sheet (the "Term Sheet") to the Company proposing that the Company consider a sale of the Company or other potential restructuring transaction. The Term Sheet proposed a transaction whereby the Company would sell substantially all of its assets or if such sale is not successful engage in a restructuring of the outstanding indebtedness of the Company, which may include a court-approved bankruptcy sale process that pays Ares, as holder of all of the Company's outstanding secured indebtedness, in full or a Chapter 11 plan or reorganization that provides for an exchange of a portion of the Ares indebtedness for 100% of the equity of the Company.

On July 23, 2018, the two directors of the Company originally nominated by Ares, Nathan W. Walton and Ronald D. Scott, resigned from the board of directors of the Company. To the knowledge of the Company at the time of this filing, the funds managed indirectly by Ares continue to hold all of the outstanding indebtedness of the Company under the Term Loan and the Convertible Notes.

At the time of the filing of these unaudited condensed consolidated financial statements as part of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, the Company and its advisors were considering the Term Sheet and evaluating alternatives for recommendation to the board of directors of the Company. Additionally, the Company and its advisors, with oversight from the Strategy Committee, are engaging in a restructuring process to consider potential strategic transactions, including financing, refinancing, sale or merger transactions and is encouraging proposals from existing stakeholders and interested third-parties. The Company has also recently elected to suspend its current operated drilling and development program in order to preserve capital for other cash needs including debt service while it considers other strategic alternatives or a possible restructuring of the Company's debt and equity. The Company believes it needs to consummate a substantial financing, refinancing, or other financial restructuring in the relative near term to re-engage in normal operated drilling activities and fund a go-forward development plan. There is no assurance that a sale of significant assets of the Company, a sale of the Company or a transaction involving a restructuring of the Company will occur.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our co-participants to fund any or all of their portion of any capital program;
- the ability to find, acquire, develop and produce new oil and natural gas properties;
- uncertainties about the estimated quantities of oil and natural gas reserves and in the projection of future rates of production and timing of development expenditures of proved reserves;
- strength and financial resources of competitors;
- availability and cost of material and equipment, such as drilling rigs and transportation pipelines;
- availability and cost of processing and transportation;
- changes or advances in technology;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry wells, operating hazards inherent to the oil and natural gas business and down hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells or pipeline mishaps;
- environmental risks;
- possible new legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, national healthcare, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, environmental risks and liability under federal, state and local environmental laws and regulations;
- effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;
- potential losses from pending or possible future claims, litigation or enforcement actions;
- potential defects in title to our properties or lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;
- the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;
- our ability to find and retain skilled personnel; and
- any other factors that impact or could impact the exploration of natural gas or oil resources, including, but not limited to, the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

For a more detailed description of the risks and uncertainties that we face and other factors that could affect our financial performance or cause our actual results to differ materially from our projected results please see (i) Part II, Item 1A. “Risk Factors” and elsewhere in this report, (ii) Part I, Item 1A. “Risk Factors” and elsewhere in our 2017 Form 10-K, (iii) our subsequent reports and registration statements filed from time to time with the SEC and (iv) other announcements we make from time to time.

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

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

Overview

We are a pure play Mid-Continent independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. We hold a concentrated acreage position in the normally pressured oil window of the STACK Play, an area of central Oklahoma which is home to multiple oil and natural gas-rich reservoirs including the Oswego limestone, Meramec and Osage bench formations within the Mississippi Lime, the Woodford shale and Hunton limestone formations.

All of our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. As of June 30, 2018, our major assets consist of approximately 97,400 gross (69,400 net) acres in Oklahoma (73% developed) deemed to have multi-STACK Play potential.

The following discussion addresses material changes in our results of operations for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 and material changes in our financial condition since December 31, 2017. This discussion should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in Part I, Item 1. "Financial Statements" of this report, as well as our 2017 Form 10-K, which includes important disclosures regarding our critical accounting policies as part of Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2017 Form 10-K.

Ability to Continue as a Going Concern

Our unaudited condensed consolidated financial statements as of and for the three and six months ended June 30, 2018 contained in this report were prepared assuming that we will continue as a going concern, which contemplates realization of assets and the satisfaction of liabilities in the normal course of business for the twelve-month period following the date of issuance of the unaudited condensed consolidated financial statements. The significant risks and uncertainties related to our liquidity and possible acceleration of our indebtedness described herein raise substantial doubt about our ability to continue as a going concern. See "Part II – Item 1A. Risk Factors" for a discussion of certain risks that materially impact our future liquidity.

Our ability to raise additional capital to pursue corporate objectives such as a drilling and development program at a cost of capital that enables our business to achieve a profit has been significantly adversely affected by our current capital structure. While, historically, we have been able to reduce capital expenditures to better match available capital resources, for the reasons described below, we do not believe we have the ability to reduce capital expenditures beyond suspension of our operated drilling program without creating the potential for deterioration to our core business. Over the past three months, we have engaged in discussions with potential capital providers that, to date, have not resulted in agreement on a restructuring or capital raising transaction. Without any apparent sources of additional capital, we have engaged in a broader restructuring process, including the engagement of legal and financial advisors to assist in exploring strategic alternatives. In addition, as a result of the recent further significant deterioration of our equity trading values, we run a significant risk that our common and preferred stock will be delisted from the NYSE American stock exchange, which delisting could cause an event of default under our indebtedness and give the holders thereof the right to accelerate the maturity of such indebtedness. See "Part II – Item 1A. Risk Factors" for a discussion of certain risks related to the potential delisting of our stock from the NYSE American.

To address the foregoing concerns, we have formed a special committee of our board of directors (the "Strategy Committee") and the Company and its advisors are considering the non-binding preliminary term sheet (the "Term

Sheet") from funds affiliated with Ares Management, L.P. proposing a potential restructuring transaction through a sale, among other means, and evaluating other alternatives for recommendation to the board of directors of the Company. In connection with developing and evaluating alternatives for our board of directors, we are engaging in a restructuring process to consider potential strategic transactions, including financing, refinancing, sale, or merger transactions, and is encouraging proposals from existing stakeholders and interested third-parties. We have also recently elected to suspend our current operated drilling and development program in order to preserve capital for other cash needs including debt service while we consider other strategic alternatives or a possible restructuring of our debt and equity. With the suspension of the operated drilling program, it is unlikely that we could further reduce capital expenditures without creating the risk for deterioration of our core business. Thus, we have determined that it is appropriate to pursue a broader restructuring process at this time. While there are certain costs attendant to pursuing such a process, we believe that incurring these costs at this time will ultimately allow us to maximize value for the benefit of our stakeholders. We believe that delaying the exploration of comprehensive restructuring and strategic alternatives could potentially lead to a restructuring at a later date, when we lack the liquidity to fund an organized process, which could ultimately lead to the loss of significant value. We intend to maintain our capital budget to preserve our current acreage position and to continue participation in selected non-operated drilling activity. But we believe we need to consummate a substantial financing, refinancing, or other financial restructuring in the relative near term to re-engage in normal drilling activities and fund its go-forward development plan.

Recent Developments

On July 20, 2018, Ares Management, L.P. and certain affiliated funds that hold substantially all of our indebtedness delivered the Term Sheet to us proposing that we consider a sale of the Company or other potential restructuring transaction. The Term Sheet proposed a transaction whereby we would sell substantially all of our assets and distribute proceeds in full satisfaction of our indebtedness. Alternatively, if such sale is not successful, the Term Sheet proposed that we engage in a restructuring of our outstanding indebtedness which may include a court-approved bankruptcy sale process that pays Ares, as holders of all of our outstanding secured indebtedness, in full or a Chapter 11 plan of reorganization that provides for an exchange of a portion of the Ares indebtedness for 100% of the equity of the Company.

On July 23, 2018, the two directors of the Company originally nominated by Ares, Nathan W. Walton and Ronald D. Scott, resigned from the board of directors of the Company. To our knowledge at the time of this filing, the funds indirectly managed by Ares continue to hold all of the outstanding indebtedness of the Company under the Term Loan and the Convertible Notes.

At the time of the filing of these unaudited condensed consolidated financial statements as part of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, we and our advisors were considering the Term Sheet and evaluating alternatives for recommendation to the board of directors of the Company. Additionally, we are engaging in a restructuring process to consider potential strategic transactions, including financing, refinancing, sale, or merger transactions, and is encouraging proposals from existing stakeholders and interested third-parties. There is no assurance that a sale of significant assets of the Company, a sale of the Company or a transaction involving a restructuring of the Company will occur.

Oil and Natural Gas Activities

The following provides an overview of our major oil and natural gas projects. While actively pursuing specific exploration and development activities in the Mid-Continent area, there is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled. We have recently elected to suspend our current operated drilling and development program in order to preserve capital for other cash needs, including debt service, while we consider other strategic alternatives or a possible restructuring of our debt and equity. We intend to maintain our capital budget to preserve our current acreage position and to continue participation in selected non-operated drilling activity. We believe we need to consummate a substantial financing, refinancing, or other financial restructuring in the relative near term to re-engage in normal drilling activities and fund a go-forward development plan.

Mid-Continent Horizontal Oil Play.

We believe that our acreage is prospective in the normally pressured oil window of the STACK Play, an area of central Oklahoma that includes oil and natural gas-rich formations such as the Meramec, Osage and Woodford shale, ranging in depth from 6,000 to 9,000 feet, and in the shallow Oswego formation as well as the proven Hunton limestone horizontal oil play. We believe that the STACK Play is one of the most economic plays in North America. It is a horizontal drilling play in an area of previously drilled vertical wells with multiple productive reservoirs that are predominantly oil producing. The STACK Play encompasses all or parts of Blaine, Canadian, Garfield, Kingfisher and Major counties in Oklahoma. STACK is an acronym for Sooner Trend Anadarko basin Canadian and Kingfisher counties. At June 30, 2018, we held leases covering approximately 97,400 gross (69,400 net) acres primarily in Garfield and Kingfisher Counties, Oklahoma within the STACK Play.

Our initial leasing activities in 2012 were primarily focused in northwest Kingfisher County, Oklahoma with an AMI co-participant whom we bought out and assumed operatorship of the acquired wells in December 2015.

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 in Kingfisher County, Oklahoma (the "Development Agreement"). The drilling program (the "Drilling Program") targeted the Meramec and Osage formations within the Mississippi Lime in a contract area within three townships covering approximately 32,900 gross (21,200 net) undeveloped net mineral acres under leases held by us. We serve as operator of all Drilling Program wells.

Under the Development Agreement, the Investor funded 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 paid 10% of our working interest portion of such costs for 20% of our original working interest in the well.

The Drilling Program wells were to 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, were mutually agreed upon by us and the Investor. Participation in the second tranche of 20 Drilling Program wells was to be at the election of the Investor and the third tranche of 20 wells was to require mutual consent. By December 31, 2017, we had drilled and completed all 20 gross (3.2 net) wells under the first tranche of the Development Agreement, all of which were on production. As of July 31, 2017, the Investor elected not to participate in a second tranche of wells.

With respect to each 20 wells drilled under the Drilling Program, when the Investor has achieved an aggregate 15% internal rate of return for its investment for all wells, 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. If and when the internal rate of return of 20% for all 20 wells in the aggregate is achieved by the Investor, the Investor's working interest decreases to 10% and our working interest increases to 90% of the working interest originally owned by us (the "final reversion").

If and when the final reversion of working interest in the completed 20 well tranche should occur, 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 remaining interest in the 20 wells in the Drilling Program (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, 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 August 19, 2024, Investor will, for a period of six months thereafter, have the right to cause us to buy Investor's then-current interest in the Drilling Program wells at an agreed upon valuation. Based on current commodity prices, well cost and production performance of the wells drilled in the first tranche, the 15% internal rate of return is not anticipated to be achieved.

During the three months ended June 30, 2018, we spud four gross (3.7 net) operated Osage wells and commenced flow back on five gross (4.9 net) operated Osage wells. During the six months ended June 30, 2018, we spud eight gross (7.4 net) operated Osage wells and commenced flow back on seven gross (6.7 net) operated Osage wells. During the three and six months ended June 30, 2018, we spud two gross (1.9 net) operated Meramec wells. Subsequent to June 30, 2018 through August 1, 2018, we spud two gross (1.5 net) operated Osage wells.

To date in 2018, we have elected to participate in various non-operated wells in the Meramec, Osage and Oswego formations to further delineate our STACK Play acreage position. Of the 2018 non-operated wells that we have elected to participate, currently four gross (0.5 net) non-operated Meramec wells, seven gross (1.2 net) non-operated Osage wells and seven gross (0.4 net) non-operated Oswego wells have been placed on production. We anticipate that we will continue to receive election notices regarding proposed non-operated STACK wells.

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

Mid-Continent - Total	For the Three Months Ended June 30, 2018	2017	For the Six Months Ended June 30, 2018	2017
Net Production:				
Oil and condensate (MBbl)	241	277	583	527
Natural gas (MMcf)	1,075	923	2,138	1,784
NGLs (MBbl)	99	128	243	245
Total net production (MBoe)	519	559	1,183	1,070
Net Daily Production:				
Oil and condensate (MBbl/d)	2.6	3.0	3.2	2.9
Natural gas (MMcf/d)	11.8	10.1	11.8	9.9
NGLs (MBbl/d)	1.1	1.4	1.3	1.4
Total net daily production (MBoe/d)	5.7	6.1	6.5	5.9
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$ 66.81	$ 45.93	$63.52	$47.28
Natural gas (per Mcf)	$ 1.35	$ 2.54	$1.70	$2.76
NGLs (per Bbl)	$ 19.58	$ 17.01	$21.48	$19.45
Average sales price per Boe(1)	$ 37.51	$ 30.88	$38.82	$32.37
Selected operating expenses (in thousands):				
Production taxes	$ 614	$ 485	$1,603	$970
Lease operating expenses	$ 4,771	$ 5,154	$12,280	$10,220
Transportation, treating and gathering(2)	$ —	$ 439	$—	$750
Selected operating expenses per Boe:				
Production taxes	$ 1.18	$ 0.87	$1.36	$0.91
Lease operating expenses	$ 9.19	$ 9.22	$10.38	$9.55
Transportation, treating and gathering(2)	$ —	$ 0.78	$-	$0.70
Production costs(3)	$ 9.19	$ 10.00	$10.38	$10.25

(1) Excludes the impact of hedging activities. Average sales prices per unit for 2018 are net of treating, transportation and gathering costs, which were previously reported separately as expenses.

(2) Pursuant to current accounting guidance, transportation, treating and gathering costs for 2018 are recorded as a reduction to revenue.

(3) Production costs for 2018 include lease operating expense (“LOE”), insurance, and workover expense and exclude ad valorem and severance taxes and transportation, treating and gathering expense. Production costs for 2017 include LOE, insurance, transportation, treating and gathering and workover expense and exclude ad valorem and severance taxes.

The following tables provide detailed production and operational information for the STACK Play and WEHLU areas that makeup the total Mid-Continent above. We completed the sale of WEHLU on February 28, 2018.

	For the Three Months Ended		For the Six Months Ended	
	June 30,		June 30,	
Mid-Continent - STACK Play excluding WEHLU	2018	2017	2018	2017
Net Production:				
Oil and condensate (MBbl)	241	125	502	224
Natural gas (MMcf)	1,075	489	1,894	923
NGLs (MBbl)	99	54	195	101
Total net production (MBoe)	519	260	1,013	479
Net Daily Production:				
Oil and condensate (MBbl/d)	2.6	1.4	2.8	1.2
Natural gas (MMcf/d)	11.8	5.4	10.5	5.1
NGLs (MBbl/d)	1.1	0.6	1.1	0.6
Total net daily production (MBoe/d)	5.7	2.9	5.6	2.6
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$ 66.81	$ 46.24	$ 63.90	$ 47.36
Natural gas (per Mcf)	$ 1.35	$ 2.76	$ 1.58	$ 2.88
NGLs (per Bbl)	$ 19.58	$ 18.32	$ 21.04	$ 20.76
Average sales price per Boe(1)	$ 37.51	$ 31.15	$ 38.68	$ 32.09
Selected operating expenses (in thousands):				
Production taxes	$ 620	$ 185	$ 1,137	$ 346
Lease operating expenses	$ 4,771	$ 2,520	$ 10,097	$ 4,674
Transportation, treating and gathering(2)	$ —	$ 439	$ —	$ 751
Selected operating expenses per Boe:				
Production taxes	$ 1.19	$ 0.71	$ 1.12	$ 0.72
Lease operating expenses(2)	$ 9.19	$ 9.70	$ 9.97	$ 9.76
Transportation, treating and gathering	$ —	$ 1.69	$ —	$ 1.57
Production costs(3)	$ 9.19	$ 11.39	$ 9.97	$ 11.33

(1) Excludes the impact of hedging activities. Average sales prices per unit for 2018 are net of treating, transportation and gathering costs, which were previously reported separately as expenses.
(2) Pursuant to current accounting guidance, transportation, treating and gathering costs for 2018 are recorded as a reduction to revenue.
(3) Production costs for 2018 include LOE, insurance, and workover expense and exclude ad valorem and severance taxes and transportation, treating and gathering expense. Production costs for 2017 include LOE, insurance, transportation, treating and gathering and workover expense and exclude ad valorem and severance taxes.

Mid-Continent - WEHLU	For the Three Months Ended June 30, 2018	2017	For the Six Months Ended June 30, 2018	2017
Net Production:				
Oil and condensate (MBbl)	—	153	81	303
Natural gas (MMcf)	—	433	243	861
NGLs (MBbl)	—	74	48	144
Total net production (MBoe)	—	300	170	591
Net Daily Production:				
Oil and condensate (MBbl/d)	—	1.7	0.4	1.7
Natural gas (MMcf/d)	—	4.8	1.3	4.8
NGLs (MBbl/d)	—	0.8	0.3	0.8
Total net daily production (MBoe/d)	—	3.3	0.9	3.3
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$—	$45.68	$61.17	$47.23
Natural gas (per Mcf)	$—	$2.30	$2.66	$2.64
NGLs (per Bbl)	$—	$16.07	$23.28	$18.53
Average sales price per Boe(1)	$—	$30.64	$39.67	$32.59
Selected operating expenses (in thousands):				
Production taxes	$(5)	$300	$466	$624
Lease operating expenses	$—	$2,634	$2,183	$5,546
Transportation, treating and gathering(2)	$—	$—	$—	$—
Selected operating expenses per Boe:				
Production taxes	$—	$1.00	$2.75	$1.06
Lease operating expenses	$—	$8.79	$12.85	$9.38
Transportation, treating and gathering(2)	$—	$—	$—	$—
Production costs(3)	$—	$8.79	$12.85	$9.38

(1) Excludes the impact of hedging activities. Average sales prices per unit for 2018 are net of treating, transportation and gathering costs, which were previously reported separately as expenses.

(2) Pursuant to current accounting guidance, transportation, treating and gathering costs for 2018 are recorded as a reduction to revenue.

(3) Production costs for 2018 include LOE, insurance, and workover expense and exclude ad valorem and severance taxes and transportation, treating and gathering expense. Production costs for 2017 include LOE, insurance, transportation, treating and gathering and workover expense and exclude ad valorem and severance taxes.

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Results of Operations

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands, except per unit amounts)			
Net Production:				
Oil and condensate (MBbl)	241	277	583	527
Natural gas (MMcf)	1,075	923	2,138	1,785
NGLs (MBbl)	99	128	243	245
Total net production (MBoe)	519	559	1,183	1,070
Net Daily Production:				
Oil and condensate (MBbl/d)	2.6	3.0	3.2	2.9
Natural gas (MMcf/d)	11.8	10.1	11.8	9.9
NGLs (MBbl/d)	1.1	1.4	1.3	1.4
Total net daily production (MBoe/d)	5.7	6.1	6.5	5.9
Average sales price per unit(1):				
Oil and condensate per Bbl, excluding impact of hedging activities	$66.80	$45.94	$63.52	$47.28
Oil and condensate per Bbl, including impact of hedging activities(2)	$55.44	$52.21	$55.31	$53.31
Natural gas per Mcf, excluding impact of hedging activities	$1.35	$2.54	$1.70	$2.76
Natural gas per Mcf, including impact of hedging activities(2)	$1.44	$2.51	$1.84	$2.85
NGLs per Bbl, excluding impact of hedging activities	$19.58	$17.02	$21.48	$19.45
NGLs per Bbl, including impact of hedging activities(2)	$14.73	$19.41	$18.01	$21.74
Average sales price per Boe, excluding impact of hedging activities	$37.51	$30.88	$38.82	$32.37
Average sales price per Boe, including impact of hedging activities(2)	$31.49	$34.49	$34.32	$36.02

Selected operating expenses:				
Production taxes	$614	$469	$1,603	$954
Lease operating expenses	$4,771	$5,146	$12,280	$10,218
Transportation, treating and gathering(3)	$—	$440	$—	$751
Depreciation, depletion and amortization	$7,588	$6,051	$16,566	$10,703
Impairment of natural gas and oil properties	$17,993	$—	$17,993	$—
General and administrative expense	$4,861	$4,591	$13,829	$8,415
Selected operating expenses per Boe:				
Production taxes	$1.18	$0.84	$1.36	$0.89
Lease operating expenses	$9.19	$9.20	$10.38	$9.55
Transportation, treating and gathering(3)	$—	$0.79	$—	$0.70
Depreciation, depletion and amortization	$14.61	$10.82	$14.01	$10.00
General and administrative expense	$9.36	$8.21	$11.69	$7.86
Production costs(4)	$9.19	$9.99	$10.38	$10.25

(1) Average sales prices per unit for 2018 are net of treating, transportation and gathering costs, which were previously reported separately as expenses.
(2) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.
(3) Pursuant to current accounting guidance, transportation, treating and gathering costs for 2018 are recorded as a reduction to revenue.
(4) Production costs for 2018 include LOE, insurance, and workover expense and exclude ad valorem and severance taxes and transportation, treating and gathering expense. Production costs for 2017 include LOE, insurance, transportation, treating and gathering and workover expense and exclude ad valorem and severance taxes.

Three Months Ended June 30, 2018 compared to the Three Months Ended June 30, 2017

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) as reported were $19.5 million for the three months ended June 30, 2018, up 13% from $17.3 million for the three months ended June 30, 2017. Pursuant to current accounting guidance, total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2018 were net of $1.2 million of treating, transportation and gathering costs which historically have been reported separately as an expense. The increase in revenues was the result of a 21% increase in weighted average realized equivalent prices partially offset by a 7% decrease in production. Average daily production on an equivalent basis was 5.7 MBoe/d for the three months ended June 30, 2018 compared to 6.1 MBoe/d for the same period in 2017. Average daily production on an equivalent basis for the three months ended June 30, 2017 included 3.3 MBoe/d of WEHLU production. The WEHLU sale closed on February 28, 2018. STACK only average daily equivalent production on an equivalent basis was 5.7 MBoe/d for the three months ended June 30, 2018 compared to 2.9 MBoe/d for the same period in 2017. STACK only oil, condensate and NGLs production represented approximately 66% of total production for the three months ended June 30, 2018 compared to 69% of total production for the three months ended June 30, 2017.

Oil and condensate revenues as reported represented approximately 83% and 74% of our total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2018 and 2017, respectively. Total liquids revenues (oil, condensate and NGLs) as reported represented approximately 93% of our total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2018 and 86% of our total oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2017.

During the three months ended June 30, 2018, we had commodity derivative contracts covering approximately 110% of our oil and condensate production. The impact of hedging on oil and condensate sales during the three months ended June 30, 2018 was a decrease of $2.7 million in oil and condensate revenues and resulted in a decrease in total price realized from $66.80 per Bbl to $55.44 per Bbl. The loss on oil and condensate commodity derivatives contracts settled during the period included $457,000 for the amortization of prepaid premiums. During the three months ended June 30, 2017, the impact of hedging on oil and condensate sales was an increase of $1.7 million, which resulted in an increase in total price realized from $45.94 per Bbl to $52.21 per Bbl. On a total liquids basis, we were approximately 92% hedged for the three months ended June 30, 2018. We allocated 15% of our crude hedges as price protection for our NGLs production for the quarters ended June 30, 2018 and 2017. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the three months ended June 30, 2018, we had commodity derivative contracts covering approximately 42% of our natural gas production. The impact of hedging on natural gas sales during the three months ended June 30, 2018 was an increase of $96,000 in natural gas revenues and resulted in an increase in total price realized from $1.35 per Mcf to $1.44 per Mcf, after reflecting Post-Production Expenses of $0.70 per Mcf. The gain on natural gas commodity derivatives contracts settled during the period was reduced by $34,000 for deferred put premiums. During the three months ended June 30, 2017, the impact of hedging on natural gas sales was a decrease of $26,000, which resulted in a decrease in total price realized from $2.54 per Mcf to $2.51 per Mcf. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the three months ended June 30, 2018, we had commodity derivative contracts covering approximately 47% of our NGLs production. The impact of hedging on NGLs sales during the three months ended June 30, 2018 was a decrease of $483,000 in NGLs revenues and resulted in a decrease in total price realized from $19.58 per Bbl to $14.73 per Bbl, after reflecting Post-Production Expenses of $4.67 per Bbl. The loss on NGLs commodity derivatives contracts settled during the period included $81,000 for amortization of prepaid premiums. During the three months ended June 30, 2017, the impact of hedging on NGLs sales was an increase of $307,000 in NGLs revenues which resulted in an increase in total price realized from $17.02 per Bbl to $19.41 per Bbl. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

The change in mark to market value for outstanding commodity derivatives contracts for the three months ended June 30, 2018 was a loss of $6.1 million compared to a gain of $3.4 million for the three months ended June 30, 2017. The change in the mark to market value is primarily the result of changes in hedge contracts and volumes hedged and the future price curve compared to the prior year.

For additional information regarding our oil and condensate hedging positions as of June 30, 2018, see Part I, Item 1. "Financial Statements, Note 8 – Derivative Instruments and Hedging Activity" of this report.

Production taxes. We reported production taxes of $614,000 for the three months ended June 30, 2018 compared to $469,000 for the three months ended June 30, 2017. The increase in production taxes primarily resulted from new Mid-Continent STACK Play wells and higher tax rates due to an Oklahoma state tax law change on exempt horizontal wells increasing the rate from 1% to 7%. Production taxes for the three months ended June 30, 2018 and 2017 were approximately 3.2% and 2.7%, respectively, of oil, condensate, natural gas and NGLs revenues. Effective July 1, 2018, Oklahoma state tax law for exempt horizontal wells that were taxed at 2% changed to increase the rate to 5%.

Lease operating expenses. We reported LOE of $4.8 million for the three months ended June 30, 2018 compared to $5.1 million for the three months ended June 30, 2017. Our total LOE was $9.19 per Boe for the three months ended June 30, 2018 compared to $9.20 per Boe for the same period in 2017. The decrease in LOE is due to a $2.6 million decrease in total LOE as a result of the WEHLU sale offset by a $2.3 million increase in total STACK Play LOE due to new wells higher water disposal costs. Transportation, treating and gathering. Pursuant to current accounting guidance, treating, transportation and gathering expense of $1.2 million was recorded as a reduction to oil, condensate, natural gas and NGLs revenues for the three months ended June 30, 2018. We reported treating, transportation and gathering expense of $440,000 for the three months ended June 30, 2017. The increase in these costs is due primarily to new wells and changes in Oklahoma marketing contracts from primarily percent of proceeds contracts to a combination of fixed charges basis and percent of proceeds contracts.

Depreciation, depletion and amortization. We reported depreciation, depletion and amortization ("DD&A") expense of $7.6 million for the three months ended June 30, 2018 up from $6.1 million for the three months ended June 30, 2017. The increase in DD&A expense was the result of a 35% increase in the DD&A rate due to the sale of WEHLU and the removal of PUD locations as of June 30, 2018 due to uncertainty regarding the financing required for development of PUD reserves partially offset by a 7% decrease in production. The DD&A rate for the three months ended June 30, 2018 was $14.61 per Boe compared to $10.82 per Boe for the same period in 2017.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $18.0 million for the three months ended June 30, 2018. The impairment was the result of the reclassification of PUD reserves to unproven reserves. Our PUD reserves, other than the PUD reserves associated with certain wells developed prior to June 30, 2018 or in the process of drilling and completion at June 30, 2018, were reclassified as unproved due to our inability to meet the reasonable certainty criteria for proved reserves, as prescribed under the SEC rules primarily due to the uncertainties regarding the availability and timing of funds required to develop these reserves. Had we continued to reflect the PUD reserves at June 30, 2018, we would not have recorded an impairment. A significant amount of our PUD reserves that were reclassified to unproved remain economically producible at current commodities prices, and we may report PUD reserves in future filings if we can determine that we have the financial capability to execute a development plan.

General and administrative expense. We reported general and administrative expenses of $4.9 million for the three months ended June 30, 2018 compared to $4.6 million for the three months ended June 30, 2017. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $1.2 million for the three months ended June 30, 2018 and 2017, respectively. Excluding stock-based compensation expense, general and administrative expense increased $301,000 to $3.7 million for the three months ended June 30, 2018 compared to the three months ended June 30, 2017. This increase is primarily due to higher legal and professional fees of approximately $764,000 and increased rent of $180,000 partially offset by a $330,000 decrease in personnel costs. We expect that our general and administrative expenses will increase significantly in the second half of 2018 due to additional expenses incurred in connection with our efforts to pursue strategic alternatives, including selling substantial assets of the Company, selling the Company itself or pursuing restructuring transactions.

Interest expense. We reported interest expense of $10.2 million for the three months ended June 30, 2018 compared to $8.7 million for the three months ended June 30, 2017. The increase in interest expense is due primarily to increased Term Loan interest of $1.6 million resulting from a higher interest rate and principal balance due to paid-in-kind interest offset by a $555,000 increase in capitalized interest.

Dividends on preferred stock. Dividends on preferred stock totaled $3.6 million for the three months ended June 30, 2018 comprised of $2.2 million for the Series A Preferred Stock and $1.4 million for the Series B Preferred Stock. Dividends on preferred stock totaled $3.6 million for the three months ended June 30, 2017 comprised of $2.2 million for the Series A Preferred Stock and $1.4 million for the Series B Preferred Stock. On April 9, 2018, 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 August 1, 2017 at an annualized 8.625% and 10.75%, respectively, through the payment date. The April 2018 Series A Preferred Stock dividend of $6.5 million and the Series B Preferred Stock dividend of $4.3 million were paid on April 30, 2018 to holders of record at the close of business on April 20, 2018, which paid all unpaid dividends that accumulated in respect to the Series A Preferred Stock and Series B Preferred

Stock at such time. We continued to declare and pay dividends on the Series A Preferred Stock and Series B Preferred Stock through June 30, 2018. On June 11, 2018, we elected to suspend the declaration and payment of monthly cash dividends on the Series A Preferred Stock and Series B Preferred Stock commencing July 2018 to maintain liquidity and support our capital investment program. On June 29, 2018, we entered into Amendment No. 4 to the Term Loan and the Second Supplemental Indenture, both of which prohibit us from making cash dividends or distributions on or with respect to our capital stock, other than cash dividends on our Series A Preferred Stock and our Series B Preferred Stock declared for the month of June 2018, which were paid on July 2, 2018.

Six Months Ended June 30, 2018 compared to the Six Months Ended June 30, 2017

Revenues. Total oil, condensate, natural gas and NGLs revenues (exclusive of the effects of hedging) as reported were $45.9 million for the six months ended June 30, 2018, up 33% from $34.6 million for the six months ended June 30, 2017. Pursuant to current accounting guidance, total oil, condensate, natural gas and NGLs revenues for the six months ended June 30, 2018 were net of $2.2 million of treating, transportation and gathering costs which historically have been reported separately as an expense. The increase in revenues was the result of a 20% increase in weighted average realized equivalent prices coupled with an 11% increase in production. Average daily production on an equivalent basis was 6.5 MBoe/d for the six months ended June 30, 2018 compared to 5.9 MBoe/d for the same period in 2017. Average daily production on an equivalent basis for the six months ended June 30, 2017 included 0.9 MBoe/d and 3.3 MBoe/d, respectively, of WEHLU production. The WEHLU sale closed on February 28, 2018. STACK only average daily equivalent production on an equivalent basis was 5.6 MBoe/d for the six months ended June 30, 2018 compared to 2.6 MBoe/d for the same period in 2017. STACK only oil, condensate and NGLs production represented approximately 69% of total production for the six months ended June 30, 2018 compared to 68% of total production for the six months ended June 30, 2017.

Oil and condensate revenues as reported represented approximately 81% and 72% of our total oil, condensate, natural gas and NGLs revenues for the six months ended June 30, 2018 and 2017, respectively. Total liquids revenues (oil, condensate and NGLs) as reported represented approximately 92% of our total oil, condensate, natural gas and NGLs revenues for the six months ended June 30, 2018 and 86% of our total oil, condensate, natural gas and NGLs revenues for the six months ended June 30, 2017.

During the six months ended June 30, 2018, we had commodity derivative contracts covering approximately 91% of our oil and condensate production. The impact of hedging on oil and condensate sales during the six months ended June 30, 2018 was a decrease of $4.8 million in oil and condensate revenues and resulted in a decrease in total price realized from $63.52 per Bbl to $55.31 per Bbl. The loss on oil and condensate commodity derivatives contracts settled during the period included $968,000 for the amortization of prepaid premiums. During the six months ended June 30, 2017, the impact of hedging on oil and condensate sales was an increase of $3.2 million, which resulted in an increase in total price realized from $47.28 per Bbl to $53.31 per Bbl. On a total liquids basis, we were approximately 76% hedged for the six months ended June 30, 2018. We allocated 15% of our crude hedges as price protection for our NGLs production for the six months ended June 30, 2018 and 2017. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the six months ended June 30, 2018, we had commodity derivative contracts covering approximately 56% of our natural gas production. The impact of hedging on natural gas sales during the six months ended June 30, 2018 was an increase of $308,000 in natural gas revenues and resulted in an increase in total price realized from $1.70 per Mcf to $1.84 per Mcf, after reflecting Post-Production Expenses of $0.62 per Mcf. The gain on natural gas commodity derivatives contracts settled during the period was reduced by $67,000 for deferred put premiums. During the six months ended June 30, 2017, the impact of hedging on natural gas sales was an increase of $163,000, which resulted in an increase in total price realized from $2.76 per Mcf to $2.85 per Mcf. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

During the six months ended June 30, 2018, we had commodity derivative contracts covering approximately 39% of our NGLs production. The impact of hedging on NGLs sales during the six months ended June 30, 2018 was a decrease of $845,000 in NGLs revenues and resulted in a decrease in total price realized from $21.48 per Bbl to $18.01 per Bbl, after reflecting Post-Production Expenses of $3.34 per Bbl. The loss on NGLs commodity derivatives contracts settled during the period included $171,000 for amortization of prepaid premiums. During the six months ended June 30, 2017, the impact of hedging on NGLs sales was an increase of $561,000 in NGLs revenues which resulted in an increase in total price realized from $19.45 per Bbl to $21.74 per Bbl. We have not designated any of these derivatives contracts as hedges as prescribed by accounting rules.

The change in mark to market value for outstanding commodity derivatives contracts for the six months ended June 30, 2018 was a loss of $9.5 million compared to a gain of $2.8 million for the six months ended June 30, 2017. The change in the mark to market value is primarily the result of changes in hedge contracts and volumes hedged and the future price curve compared to the prior year.

For additional information regarding our oil and condensate hedging positions as of June 30, 2018, see Part I, Item 1. "Financial Statements, Note 8 – Derivative Instruments and Hedging Activity" of this report.

Production taxes. We reported production taxes of $1.6 million for the six months ended June 30, 2018 compared to $954,000 for the six months ended June 30, 2017. The increase in production taxes primarily resulted from new Mid-Continent STACK Play wells and higher tax rates due to an Oklahoma state tax law change on exempt horizontal wells increasing the rate from 1% to 7%. Production taxes for the six months ended June 30, 2018 and 2017 were approximately 3.5% and 2.8%, respectively, of oil, condensate, natural gas and NGLs revenues. Effective July 1, 2018, Oklahoma state tax law for exempt horizontal wells that were taxed at 2% changed to increase the rate to 5%.

Lease operating expenses. We reported LOE of $12.3 million for the six months ended June 30, 2018 compared to $10.2 million for the six months ended June 30, 2017. Our total LOE was $10.38 per Boe for the six months ended June 30, 2018 compared to $9.55 per Boe for the same period in 2017. The increase in LOE is primarily due to a $5.0 million increase in recurring STACK Play LOE due to new wells with higher water disposal costs coupled with a $389,000 increase in workover costs offset by a $3.4 million decrease in LOE costs eliminated with the sale of WEHLU.

Transportation, treating and gathering. Pursuant to current accounting guidance, treating, transportation and gathering expense of $2.2 million was recorded as a reduction to oil, condensate, natural gas and NGLs revenues for the six months ended June 30, 2018. We reported treating, transportation and gathering expense of $751,000 for the six months ended June 30, 2017. The increase in these costs is due primarily to new wells and changes in Oklahoma marketing contracts from primarily percent of proceeds contracts to a combination of fixed charges basis and percent of proceeds contracts.

Depreciation, depletion and amortization. We reported DD&A expense of $16.6 million for the six months ended June 30, 2018 up from $10.7 million for the six months ended June 30, 2017. The increase in DD&A expense was the result of a 40% increase in the DD&A rate due to the sale of WEHLU during the first quarter of 2018 and the removal of PUD locations as of June 30, 2018 due uncertainty regarding the financing required to develop PUD reserves coupled with an 11% increase in production. The DD&A rate for the six months ended June 30, 2018 was $14.01 per Boe compared to $10.00 per Boe for the same period in 2017.

Impairment of oil and natural gas properties. We reported an impairment of oil and natural gas properties of $18.0 million for the six months ended June 30, 2018. The impairment was the result of the reclassification of PUD reserves to unproven reserves. Our PUD reserves, other than the PUD reserves associated with certain wells developed prior to June 30, 2018 or in the process of drilling and completion at June 30, 2018, were reclassified as unproved due to our inability to meet the reasonable certainty criteria for proved reserves, as prescribed under the SEC rules primarily due to the uncertainties regarding the availability and timing of funds required to develop these reserves. Had we continued to reflect the PUD reserves at June 30, 2018, we would not have recorded an impairment. A significant amount of our PUD reserves that were reclassified to unproved remain economically producible at current commodities prices, and we may report PUD reserves in future filings if we can determine that we have the financial capability to execute a development plan.

General and administrative expense. We reported general and administrative expenses of $13.8 million for the six months ended June 30, 2018 compared to $8.4 million for the six months ended June 30, 2017. Non-cash stock-based compensation expense, which is included in general and administrative expense, was $2.9 million and $2.2 million for the six months ended June 30, 2018 and 2017, respectively. Excluding stock-based compensation expense, general and administrative expense increased $4.7 million to $10.9 million for the six months ended June 30, 2018 compared to the six months ended June 30, 2017. This increase is primarily due to $3.5 million of severance costs related to the resignation of our former chief executive officer coupled with a $1.4 million increase in legal and professional fees. We expect that our general and administrative expenses will increase significantly in the second half of 2018 due to additional expenses incurred in connection with our efforts to pursue strategic alternatives, including selling substantial assets of the Company, selling the Company itself or pursuing restructuring transactions.

Interest expense. We reported interest expense of $20.1 million for the six months ended June 30, 2018 compared to $19.6 million for the six months ended June 30, 2017. The increase in interest expense is due primarily to increased Term Loan interest resulting from a higher principal balance due to paid-in-kind interest.

Loss on early extinguishment of debt. We reported a loss on early extinguishment of debt of $12.2 million for the six months ended June 30, 2017 comprised of a $7.0 million penalty for the early satisfaction and discharge of our Former Notes and the $5.2 million write-off of the remaining deferred financing costs related to the Former Notes and our Revolving Credit Facility.

Dividends on preferred stock. Dividends on preferred stock totaled $7.2 million for the six months ended June 30, 2018 comprised of $4.4 million for the Series A Preferred Stock and $2.8 million for the Series B Preferred Stock. Dividends on preferred stock totaled $7.2 million for the six months ended June 30, 2017 comprised of $4.4 million for the Series A Preferred Stock and $2.8 million for the Series B Preferred Stock. On April 9, 2018, 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 August 1, 2017 at an annualized 8.625% and 10.75%, respectively, through the payment date. The April 2018 Series A Preferred Stock dividend of $6.5 million and the Series B Preferred Stock dividend of $4.3 million were paid on April 30, 2018 to holders of record at the close of business on

April 20, 2018, which paid all unpaid dividends that accumulated in respect to the Series A Preferred Stock and Series B Preferred Stock at such time. We continued to declare and pay dividends on the Series A Preferred Stock and Series B Preferred Stock through June 30, 2018. On June 11, 2018, we elected to suspend the declaration and payment of monthly cash dividends on the Series A Preferred Stock and Series B Preferred Stock commencing July 2018 to maintain liquidity and support our capital investment program. On June 29, 2018, we entered into Amendment No. 4 to the Term Loan and the Second Supplemental Indenture, both of which prohibit us from making cash dividends or distributions on or with respect to our capital stock, other than cash dividends on our Series A Preferred Stock and our Series B Preferred Stock declared for the month of June 2018, which were paid on July 2, 2018.

Liquidity and Capital Resources

Overview. Our decisions regarding capital structure, hedging and drilling are based upon many factors, including anticipated future commodity pricing, expected economic conditions and recoverable reserves. Our primary sources of liquidity and capital resources are existing cash balances, internally generated cash flows from operating activities, asset sales and possible capital markets transactions, to the extent available on acceptable terms. Our cash flows from operations are impacted by various factors, the most significant of which is the market pricing for oil, condensate, natural gas and NGLs. The pricing for these commodities is volatile, and the factors that impact such market pricing are global and therefore outside of our control. Volatility in commodity prices also impacts estimated quantities of proved reserves. Our longer term operating cash flows are dependent upon reserve replacement and the level of costs required for ongoing operations. We are required to make investments to fund activity necessary to offset the inherent declines in production and proved crude oil and natural gas reserves. Our ability to maintain and grow reserves and production is highly dependent on the success of our drilling program and our ability to add reserves economically.

We have recently elected to suspend our current operated drilling and development program in order to preserve capital for other cash needs including debt service while we consider other strategic alternatives or a possible restructuring of our debt and equity. In addition, we expect our general and administrative expenses may increase significantly in the second half of 2018 due to anticipated additional expenses incurred in connection with our efforts to pursue strategic alternatives, including selling substantial assets of the Company, selling the Company itself or pursuing restructuring transactions. As a result, it is not possible for us to precisely predict our future cash flows from operating revenues. See "Part II – Item 1A Risk Factors" for a discussion of certain risks that materially impact our future liquidity.

We continually evaluate our capital needs and compare them to our available capital resources and ability to raise funds in the financial markets. Current market conditions and restrictions under our debt may put limitations on our ability to issue additional debt or equity securities in the public or private markets, which may significantly reduce our ability to obtain liquidity. We operate the majority of our capital expenditures budget, and we have the ability to adjust capital expenditures in response to changes that would potentially reduce our available capital resources, including changes in oil, condensate, natural gas and NGLs prices, drilling results, liquidity and cash flow. We have recently elected to suspend our current operated drilling and development program in order to preserve capital for other cash needs including debt service while we consider other strategic alternatives or a possible restructuring of our debt and equity.

For the six months ended June 30, 2018, we reported cash flows provided by operating activities of $39.3 million. For the six months ended June 30, 2018, we reported net cash provided by investing activities of $12.0 million primarily due to the inclusion of proceeds from the sale oil and natural gas properties of $96.3 million offset by $83.4 million for the development of oil and natural gas properties. For the six months ended June 30, 2018, we reported net cash used in financing activities of $13.5 million primarily due to $12.1 million in dividends declared and paid and $1.2 million for tax withholding related to restricted stock award vestings. As a result of these activities, our cash and cash equivalents balance increased by $37.8 million, resulting in a cash and cash equivalents balance of $51.1 million at June 30, 2018.

At June 30, 2018, we had a net working capital surplus of approximately $4.9 million. As of August 7, 2018, our cash balance was $32.5 million and we had $276.8 million of Term Loan borrowings and $162.5 million of Notes outstanding with a maturity of March 2022.

Future capital and other expenditure requirements. As a result of our decision to suspend our current operated drilling and development program in order to preserve capital, we have revised our estimates of capital expenditures for the remainder of 2018, which are estimated to be approximately $45.3 million which contemplates $16.5 million for STACK Play operated drilling and completion activity on wells being drilled prior to or at June 30, 2018, $17.7 million for our participation in non-operated STACK Play drilling and completions, $6.2 million for leasehold costs to preserve our current acreage position and $4.9 million for capitalized general and administrative costs. We plan to fund our remaining 2018 capital budget through existing cash balances 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, higher working interest in drilled wells, reductions in liquidity and access to additional capital.

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, fixed price swaps and put and call options to hedge oil, condensate, natural gas and NGLs price risk. The crude oil fixed price swaps provide price protection for our future oil sales and butane, isobutene and pentanes components of our NGLs production as these heavy components of NGLs have pricing that correlates closely with oil pricing. For 2018, we have allocated 15% of our current crude hedges as price protection for a portion of our NGLs production. We have not designated any of these derivative contracts as hedges as prescribed by accounting rules. For additional information regarding our hedging activities, see Part I, Item 1. “Financial Statements, Note 8 – Derivative Instruments and Hedging Activity” of this report.

At June 30, 2018, the estimated fair value of all of our commodity derivative instruments was a net liability of $15.7 million, comprised of current and non-current assets and liabilities. By removing the price volatility from a portion of our oil, condensate, natural gas and NGLs sales for July 2018 through December 2019, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flows for those periods. While mitigating negative effects of falling commodity prices, certain derivative contracts also limit the benefits we could receive from increases in commodity prices. In conjunction with certain commodity derivative hedging activity, we deferred the payment of certain put premiums for the production month period July 2018 through December 2018. At June 30, 2018, we had a current commodity premium payable of $68,000. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month.

As of June 30, 2018, all of our commodity derivative hedge positions were with large institutions, each of which is not known to us to be in default on their derivative positions. We are exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, we do not anticipate non-performance by such counterparties.

Term Loan Facility. On March 3, 2017, the Company entered into a $250.0 million Term Loan pursuant to the Third Amended and Restated Credit Agreement among the Company, as borrower, the guarantors party thereto, funds managed indirectly by Ares Management LLC, as lenders, and Wilmington Trust, National Association, as Administrative Agent (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 31, June 30, September 30 and December 31 of each year, commencing March 31, 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.

On March 20, 2017, we, together with the parties thereto, entered into an Amendment No. 1 to the Term Loan credit agreement which amendment permitted the issuance of the Additional Notes.

On August 2, 2017, we entered into Amendment No. 2 to the Term Loan credit agreement allowing us to elect to PIK interest on the Term Loan, upon proper notice, 100% of interest payments due after June 30, 2017 and prior to December 1, 2018 and at our election, PIK between 0% and 50% of any interest payments occurring after December 31, 2018 (other than interest due on the maturity date or the date of any repayment or prepayment). The Term Loan interest rate increased to 10.25% for all interest periods post June 30, 2017 and the PIK interest shall be payable by capitalizing and adding such amounts to the outstanding principal amount of the Term Loan on the applicable interest payment date.

On September 18, 2017, we, together with the parties thereto, entered into Amendment No. 3 to the Term Loan credit agreement, which among other things, expressly provided that certain assignments of oil and gas properties made or to be made by the Company to Red Bluff, pursuant to the Red Bluff PSA, are permitted by the Term Loan and are not subject to the mandatory prepayment provisions applicable to "Asset Sales" under the Term Loan.

On June 29, 2018, we entered into Amendment No. 4 to the Term Loan credit agreement, which among other things, (i) reduced the period we could cure a default resulting from the failure to comply with certain covenants applicable to the Term Loan from 30 days to 15 days, (ii) waived certain defaults under the Term Loan and (iii) prohibited us from making cash dividends or distributions on or with respect to our capital stock, other than cash dividends on our Series A Preferred Stock and Series B Preferred Stock declared for the month of June 2018 and paid on July 2, 2018.

The Term Loan is secured by a first-priority lien on substantially all of the assets of the Company and its sole 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, 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.

Pursuant to Amendment No. 2 to the Term Loan credit agreement, we elected to pay in kind 100% of the interest due for the period June 30, 2017 to April 1, 2018 in the amount of $19.9 million, thus increasing the outstanding principal balance of the Term Loan to $269.9 million. We also elected to pay in kind 100% of the interest due for the period April 2, 2018 to June 30, 2018 in the amount of $6.7 million and such was accrued at June 30, 2018. Had the interest payment date not fallen on a weekend outside of quarter end, the outstanding principal balance of the Term Loan would have been $276.6 million at June 30, 2018.

Notes. On March 3, 2017 and March 21, 2017, we issued for cash at par $125.0 million and $75.0 million, respectively, principal amounts of Convertible Notes due 2022 (the "Notes") under an Indenture by and among the Company, the subsidiary guarantor named therein, and the Trustee and collateral trustee. The Notes bear interest initially at 6.0% per annum. On May 5, 2017, $37.5 million principal amount of the Notes were exchanged for 25,456,521 newly issued shares of our common stock and 2,000 shares of Special Voting Preferred Stock pursuant to the Mandatory Repurchase, reducing the outstanding principal amount of the Notes to $162.5 million. The Notes 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.

The Notes were issued with conversion rights that were subject to receipt of the Requisite Stockholder Approval, which was obtained at a special meeting of stockholders held May 2, 2017. The Notes are 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. The Company has 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.

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 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.

On June 29, 2018, we entered into the Second Supplemental Indenture, which supplements the Indenture. The Second Supplemental Indenture, among other things, (i) waived certain defaults, (ii) reduced the period the we could cure certain covenant defaults under the Indenture from 60 days to 15 days and (iii) prohibited us and our subsidiary from making cash dividends or distributions on or with respect to our capital stock, other than cash dividends on its Series A Preferred Stock and its Series B Preferred Stock declared for the month of June 2018.

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 since April 1, 2016 at an annualized 8.625% and 10.75%, respectively, which dividend was paid on January 31, 2017. Under Amendment No. 10 to the Revolving Credit Facility, payment of the declared Series A and Series B Preferred Stock January 2017 dividend and monthly preferred stock cash dividends through May 2017 were permitted. 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.

On June 29, 2018, we entered into Amendment No. 4 to the Term Loan and into the Second Supplemental Indenture, both of which prohibit us from making cash dividends or distributions on or with respect to our capital stock, other than cash dividends on our Series A Preferred Stock and our Series B Preferred Stock declared for the month of June 2018, which were paid on July 2, 2018.

Off-Balance Sheet Arrangements

As of June 30, 2018, we had no off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Commitments and Contingencies

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

We are party to various litigation matters and administrative claims arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows. A discussion of current legal proceedings is set forth in Part I, Item 1. "Financial Statements, Note 13 – Commitments and Contingencies" of this report.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, contingent assets and liabilities and the related disclosures in the accompanying condensed consolidated financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

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

Significant accounting policies that we employ and information about the nature of our most critical accounting estimates, our assumptions or approach used and the effects of hypothetical changes in the material assumptions used to develop each estimate are presented in Part I, Item I. "Financial Statements, Note 3 – Summary of Significant Accounting Policies" of this report and in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates" included in our 2017 Form 10-K. As of June 30, 2018, with the exception of the adoption of ASC 606 as discussed in "Financial Statements, Note 3 – Summary of Significant Accounting Policies" of this report, our critical accounting policies were consistent with those discussed in our 2017 Form 10-K.

Recent Accounting Developments

For a discussion of recent accounting developments, see Part I, Item 1. "Financial Statements, Note 3 – Summary of Significant Accounting Policies" of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, NGLs, and oil prices, and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

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 three months ended June 30, 2018, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate $1.9 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. For the three months ended June 30, 2017, a 10% change in the prices received for our oil, condensate, natural gas and NGLs production would have had an approximate $1.7 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. For the six months ended June 30, 2018, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate $4.6 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. For the six months ended June 30, 2017, a 10% change in the prices received for oil, condensate, natural gas and NGLs production would have had an approximate $3.5 million impact on our revenues prior to hedge transactions to mitigate our commodity pricing risk. As of June 30, 2018, the fair market value of our commodity derivatives was a net liability of $15.7 million. As of December 31, 2017, the fair market value of our commodity derivatives was a net liability of $5.6 million. For more information regarding our hedging activities, see Part I, Item 1. "Financial Statements, Note 8 – Derivative Instruments and Hedging Activity" of this report for additional information regarding our hedging activities.

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

Interest Rate Risk

Prior to the pay-off of our Revolving Credit Facility in March 2017, we were exposed to changes in interest rates as a result of our Revolving Credit Facility. We did not enter into interest rate hedging arrangements in the past. The amount outstanding under the Term Loan was fixed at interest of 8.5% per annum prior to June 30, 2017 and is fixed at 10.25% per annum after June 30, 2017 and the amount outstanding under the Notes is at fixed interest of 6.0% per annum. Thus, we have no exposure to fluctuating interest rates.

Item 4. Controls and Procedures

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

Under the supervision and with the participation of our management, including our Interim Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended ("Exchange Act"), as of June 30, 2018. Based on that evaluation, our Interim Chief Executive Officer and Chief Financial Officer concluded that, due to the material weakness described below, as of June 30, 2018, our disclosure controls and procedures were not effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Interim Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the quarter ended June 30, 2018, an error was discovered in determining the Company's compliance with its debt covenants under the Company's secured Term Loan and Indenture under which the Company's outstanding secured Notes are issued. The failure to comply with these debt covenants resulted in defaults under both the Term Loan and Indenture, which defaults were subsequently waived on June 29, 2018. This error, which was not detected timely by management, was the result of inadequate understanding of the covenants under the Term Loan and

Indenture, and there is a reasonable possibility that the error could have resulted in a material misstatement of the financial statements. This inability to accurately monitor compliance with such debt covenants is a deficiency which represents a material weakness in the Company's internal control over financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis.

To address the material weakness described above, the Company is in the process of implementing new and enhanced controls to ensure that the quarterly debt covenant analysis and calculations are performed correctly and reviewed appropriately.

We believe the actions described above will be sufficient to remediate the identified material weakness and strengthen our internal control over financial reporting. We will continue to monitor the effectiveness of these controls and will make any further changes management determines appropriate.

Except for the Company's design and implementation of new and enhanced controls related to the material weakness described above, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the

Exchange Act) that occurred during the fiscal quarter ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

A discussion of current legal proceedings is set forth in Part I, Item 1. "Financial Statements, Note 13 – Commitments and Contingencies" of this report.

Item 1A. Risk Factors

In addition to the risk factors below and the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. "Risk Factors" in our 2017 Form 10-K, which could materially affect our business, financial condition or future results. These risks are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, operating results and cash flows.

We may not be able to continue as a going concern.

We have substantial debt obligations and our ongoing operations have historically been dependent upon spending significant capital on drilling and development of our properties. Our ability to raise additional capital to pursue corporate objectives such as a drilling and development program at a cost of capital that enables our business to achieve a profit has been significantly adversely affected by our current capital structure. We have recently elected to suspend our current operated drilling and development program in order to preserve capital for other cash needs including debt service while we consider other strategic alternatives or a possible restructuring of our debt and equity. If we are unable to raise substantial additional funding, consummate significant asset sales or consummate an alternative financial restructuring on a timely basis on acceptable terms, we will not be able to restore funding of our drilling and development operations. We do not believe we have the ability to reduce capital expenditures further without creating the potential for deterioration of our core business. We are engaging in a restructuring process to consider potential strategic transactions, including financing, refinancing, sale, or merger transactions, and are encouraging proposals from existing stakeholders and interested third-parties. There can be no assurance that we will consummate such a transaction on a timely basis.

The condensed consolidated financial statements included in this report have been prepared assuming that we will continue as a going concern and do not include any adjustments that might result from the outcome of the going concern uncertainty. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and reported amounts of income and expenses could be required and could be material. There can be no assurance that we will be able to obtain additional funding on a timely basis and on satisfactory terms, or at all. In addition, no assurance can be given that any such funding, if obtained, will be adequate to meet our capital needs and support our business plan while paying or refinancing our existing debt obligations. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then our operations would be materially negatively impacted.

If we become unable to continue as a going concern, we may find it necessary to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure. Additionally, we may find it necessary to file a petition for reorganization under Chapter 11 of the U.S.

Bankruptcy Code in order to implement a financial restructuring.

The extremely low trading price of our common stock has put us at substantial risk that our common stock and two outstanding series of preferred stock will be delisted from the NYSE American, which would further limit the liquidity of our common stock.

Our common stock has been trading at below $1.00 per share since early February 2018 and in recent weeks, has traded at as low as $0.09 per share. The staff of the NYSE American has advised us that if our common stock trades at or below $0.06 per share during any trading day, our common stock and our two outstanding series of preferred stock will be automatically suspended. We have limited ability to timely remedy a stock price deficiency to forgo a delisting.

Delisting could materially adversely affect the market for our common and preferred shares. In addition, our ability to raise additional necessary capital through equity or debt financing, and attract and retain personnel by means of equity compensation, would be greatly impaired. If our stock is delisted from the NYSE American, we cannot assure that we will be able to regain compliance or that any appeal of a decision to delist our common stock and preferred stock would be successful. If our common stock and preferred stock loses its listed status on the NYSE American and we are not successful in obtaining a listing on another exchange, our common stock and preferred stock would likely trade only in the over-the-counter market. If our common stock or preferred stock were to trade on the over-the-counter market, selling our common stock or preferred stock could be more difficult because smaller quantities of shares would likely be bought and sold, transactions could be delayed, and security analysts’ coverage of us may be reduced, if not eliminated. In addition, in the event our common stock or preferred stock is delisted, broker-dealers have certain regulatory burdens imposed upon them, which may discourage broker-dealers from effecting transactions in our common or preferred stock, further limiting the liquidity thereof. These factors could result in even lower prices and larger spreads in the bid and ask prices for our common and preferred stock, and possibly an inability to effect a trade. Furthermore, with respect to any suspended or delisted securities, we would expect decreases in institutional and other investor demand, analyst coverage, market making activity and information available concerning trading prices and volume, and fewer broker-dealers would be willing to execute trades with respect to such securities.

If our stock is delisted from the NYSE American, we would be in default under our Term Loan and obligated to offer to purchase all of our Convertible Notes in cash at a price of 101% of principal plus accrued interest which we likely cannot cure or satisfy, which could result in an event of default and permit Ares, as holder of our outstanding Term Loan and Convertible Notes or its transferees, to accelerate the maturity of our outstanding indebtedness.

A delisting of our common stock constitutes a "fundamental change" under the terms of the indenture governing our Convertible Notes. If a Fundamental Change occurs at any time prior to the maturity of the Convertible Notes, each holder shall have the right to require us to repurchase all or part of such holder's notes on the date (the "Fundamental Change Repurchase Date") specified by us that is not less than 20 nor more than 35 calendar days after the date a Fundamental Change repurchase notice at a repurchase price, payable in cash, equal to 101% of the principal amount of the Convertible Notes being repurchased, plus accrued and unpaid interest to, but excluding, the Fundamental Change Repurchase Date. Unless a significant restructuring transaction were to occur and Ares, as holder of the Term Loan, would agree, it is unlikely in such event that we would have adequate liquidity to fund such a repurchase. The failure consummate the offer to purchase to holders of Convertible Notes, which would occur upon the delisting of our common stock or upon the incurrence of certain other events, constitutes an event of default under the Term Loan credit agreement. Ares, or any transferee holder of a majority in principal amount of the Term Loan, would have the right to accelerate the maturity of the Term Loan. Any acceleration of the maturity of the Term Loan gives the indenture trustee or the holders of 25% of the outstanding principal in the Convertible Notes the right to immediately accelerate the maturity of the Convertible Notes. In the event all or a significant portion of our indebtedness becomes due as a result of this acceleration, we may be required to seek protection under Chapter 11 of the U.S. Bankruptcy Code.

We have identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future or otherwise fail to maintain an effective system of internal controls.

We are required to maintain internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. During the quarter ended June 30, 2018, we and our independent registered public accounting firm identified material weaknesses in internal control over financial reporting relating to the inability to monitor compliance with the Company's covenants under the Company's Term Loan and Indenture. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. See "Item 4 - Changes in Internal Control Over Financial Reporting."

We are in the process of remediating the identified material weakness through the design and implementation of new and enhanced controls. However, we do not expect that our internal control over financial reporting, including these enhanced controls, will prevent all future errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Over time, controls may become inadequate because changes in conditions or deterioration in the degree of compliance with policies or procedures may occur. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Our failure to maintain effective internal control over financial reporting could result in errors in our financial statements that could result in a restatement of our financial statements and cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock.

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

Issuer Purchases of Equity Securities

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

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans	(d) Maximum Number of Shares that May Yet be Purchased Under the Plan
April 1, 2018 – April 30, 2018	980,518	$0.63	—	n/a
May 1, 2018 – May 31, 2018	21,957	$0.66	—	n/a
June 1, 2018 – June 30, 2018	71,287	$0.60	—	n/a

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

Executive Retention Plan

On August 9, 2018, in accordance with the powers delegated to it by the Board, the Strategy Committee approved retention payments to four Company executives upon the recommendation of the Compensation Committee of the Board. The retention agreements ("Retention Agreements") between each such executive and the Company provide that each executive will receive a cash payment ("Retention Bonus"), representing a certain percentage of his base salary, paid in a lump sum in cash on or before August 17, 2018. In the event the executive's employment is terminated (i) by the Company for cause (as defined in the Retention Agreement) or (ii) due to his voluntarily resignation, the executive will be required to repay to the Company 100% of the Retention Bonus (net of any taxes withheld from same) if such termination occurs before December 31, 2018 and 50% of the Retention Bonus (net of taxes withheld from same) if such termination occurs after December 31, 2018 and before July 1, 2019 (the "Repayment Obligation"). The Repayment Obligation will cease in the event that the Company fails to pay the executive's base salary in accordance with the Company's normal payroll practices and fails to correct any such failure within five (5) days of written notice from the executive or upon the occurrence of a change in control (as defined in the Retention Agreement) of the Company. The Repayment Obligation set forth in Jerry Schuyler's Retention Agreement is reduced on a straight line basis from 100% (if termination occurs before September 1, 2018) to 0% (if termination occurs any time after June 1, 2019) for each additional month that he remains employed by the Company.

Retention Payments

The Strategy Committee awarded each executive named below a Retention Bonus in the respective amounts set forth below, in each case on the terms and subject to the conditions of the Retention Plan and such executive's Retention Agreement:

Executive	Retention Payment
Jerry Schuyler	$ 562,744
Michael Gerlich	$ 471,750
Stephen Roberts	$ 497,250

Item 6. Exhibits

The exhibits required to be filed or furnished pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index immediately below and such exhibits identified therein are incorporated herein by reference into this report.

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.) (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on October 28, 2013. File No. 001-35211).
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. dated July 5, 2016 (incorporated by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q filed with the SEC on August 4, 2016. File No. 001-35211).
3.3	First Certificate of Amendment of Amended and Restated Certificate of Incorporation of Gastar Exploration Inc. dated July 24, 2017 (incorporated by reference to Exhibit 3.3 of the Quarterly Report on Form 10-Q filed with the SEC on August 3, 2017. File No. 001-35211).
3.4	Amended and Restated Bylaws of Gastar Exploration Inc. dated November 4, 2015 (incorporated by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q filed with the SEC on November 5, 2015. File No. 001-35211).
3.5	Certificate of Elimination of Series C Junior Participating Preferred Stock of Gastar Exploration Inc. (incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K filed with the SEC on April 6, 2017. File No. 001-35211).
10.1	Form of Amended and Restated Indemnification Agreement (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on June 29, 2018. File No. 001-35211).
10.2	Amendment No. 4 and Limited Waiver to Third Amended and Restated Credit Agreement, dated as of June 29, 2018, among Gastar Exploration Inc., as borrower, certain subsidiaries of borrower, as guarantors, the lenders party thereto and Wilmington Trust, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed with the SEC on July 6, 2018. File No. 001-35211).
10.3	Second Supplemental Indenture, dated as of June 29, 2018, between Gastar Exploration Inc. and Wilmington Trust, National Association, as trustee and collateral trustee (incorporated by reference to Exhibit 10.2 of the Current Report on Form 8-K filed with the SEC on July 6, 2018, File No. 001-35211).
31.1†	Certification of Principal Executive Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2†	Certification of Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1††	Certification of Principal Executive Officer and Principal Financial Officer of Gastar Exploration Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS†	XBRL Instance Document
101.SCH†	XBRL Taxonomy Extension Schema Document

101.CAL†	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	XBRL Taxonomy Extension Presentation Linkbase Document

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

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SIGNATURES

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

GASTAR EXPLORATION INC.

Date:	August 9, 2018	By: /s/ JERRY R. SCHUYLER Jerry R. Schuyler Interim Chief Executive Officer and Chairman of the Board (Duly authorized officer and principal executive officer)
Date:	August 9, 2018	By: /s/ MICHAEL A. GERLICH Michael A. Gerlich Senior Vice President and Chief Financial Officer (Duly authorized officer and principal financial and accounting officer)

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