Midstates Petroleum Company, Inc.
Form 10-Q
November 14, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2017

OR

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

For the transition period from to .

Commission File Number: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**45-3691816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
321 South Boston Avenue, Suite 1000 **Tulsa, Oklahoma**	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: **(918) 947-8550**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

The number of shares outstanding of our stock at November 9, 2017 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	25,173,346

DOCUMENTS INCORPORATED BY REFERENCE

None.

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MIDSTATES PETROLEUM COMPANY, INC.

QUARTERLY REPORT ON

FORM 10-Q

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2017

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GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl: One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe: Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

Boe/day: Barrels of oil equivalent per day.

Completion: The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

Exploratory well: A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

MMBoe: One million barrels of oil equivalent.

MMBtu: One million British thermal units.

Net acres: The percentage of total acres an owner has out of a particular number of acres, or a specified tract.

NYMEX: The New York Mercantile Exchange.

Proved reserves: Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to drill or operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reasonable certainty: A high degree of confidence.

Recompletion: The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish, re-establishing, or increase existing production.

Reserves: Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations.

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Spud or Spudding: The commencement of drilling operations of a new well.

Wellbore: The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest: The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on a cash, penalty, or carried basis.

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PART I FINANCIAL INFORMATION

MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share amounts)

	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 76,548	$ 76,838
Accounts receivable:		
Oil and gas sales	29,776	36,988
Joint interest billing	3,193	4,281
Other	630	2,456
Commodity derivative contracts	2,896	
Other current assets	1,821	3,326
Total current assets	114,864	123,889
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting		
Proved properties	709,647	573,150
Unproved properties not being amortized	26,178	65,080
Other property and equipment	6,543	6,339
Less accumulated depreciation, depletion and amortization	(59,349)	(12,974)
Net property and equipment	683,019	631,595
OTHER NONCURRENT ASSETS	7,156	5,455
TOTAL	**$ 805,039**	**$ 760,939**
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 9,480	$ 2,521
Accrued liabilities	46,987	53,731
Total current liabilities	56,467	56,252
LONG-TERM LIABILITIES:		
Asset retirement obligations	14,039	14,200
Commodity derivative contracts	278	
Long-term debt	128,059	128,059
Other long-term liabilities	599	614
Total long-term liabilities	142,975	142,873
COMMITMENTS AND CONTINGENCIES (Note 14)		
STOCKHOLDERS EQUITY:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized; no shares issued or outstanding at September 30, 2017 and December 31, 2016		
Warrants, 6,625,554 warrants outstanding at September 30, 2017 and December 31, 2016	37,329	37,329
Common stock, $0.01 par value, 250,000,000 shares authorized; 25,098,834 shares issued and 25,065,425 shares outstanding at September 30, 2017 and 24,994,867 shares issued and outstanding at December 31, 2016	251	250

Treasury stock		(626)		
Additional paid-in-capital		522,823		514,305
Retained earnings		45,820		9,930
Total stockholders equity		605,597		561,814
TOTAL	**$**	**805,039**	**$**	**760,939**

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share amounts)

	Successor For the Three Months Ended September 30, 2017	Predecessor For the Three Months Ended September 30, 2016	Successor For the Nine Months Ended September 30, 2017	Predecessor For the Nine Months Ended September 30, 2016
REVENUES:				
Oil sales	$ 27,190	$ 35,584	$ 85,497	$ 104,832
Natural gas liquid sales	10,656	8,939	31,580	25,073
Natural gas sales	13,970	17,676	46,321	44,486
Gains (losses) on commodity derivative contracts net	(3,591)		8,767	
Other	1,490	1,994	3,244	4,322
Total revenues	49,715	64,193	175,409	178,713
EXPENSES:				
Lease operating and workover	15,653	17,650	48,064	49,520
Gathering and transportation	3,699	4,296	11,027	13,428
Severance and other taxes	2,352	1,788	6,168	4,776
Asset retirement accretion	274	452	833	1,316
Depreciation, depletion, and amortization	15,170	15,756	46,471	59,229
Impairment in carrying value of oil and gas properties		33,887		224,584
General and administrative	7,255	3,308	23,102	19,093
Debt restructuring costs and advisory fees				7,589
Total expenses	44,403	77,137	135,665	379,535
OPERATING INCOME (LOSS)	5,312	(12,944)	39,744	(200,822)
OTHER EXPENSE:				
Interest income				81
Interest expense net of amounts capitalized (excludes interest expense of $47.6 million and $79.3 million on senior and secured notes subject to compromise for the three and nine months ended September 30, 2016, respectively)	(1,649)	(2,668)	(3,854)	(65,719)
Reorganization items, net		(22,772)		57,764
Total other expense	(1,649)	(25,440)	(3,854)	(7,874)
INCOME (LOSS) BEFORE TAXES	**3,663**	**(38,384)**	**35,890**	**(208,696)**
Income tax expense				
NET INCOME (LOSS)	**$ 3,663**	**$ (38,384)**	**$ 35,890**	**$ (208,696)**
Successor participating securities non-vested restricted stock	(82)		(932)	
Predecessor participating securities non-vested restricted stock				
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON	**$ 3,581**	**$ (38,384)**	**$ 34,958**	**$ (208,696)**

SHAREHOLDERS				
Basic and diluted net income (loss) per share attributable to common shareholders	$ 0.14	$ (3.60)	$ 1.39	$ (19.61)
Basic and diluted weighted average number of common shares outstanding (Note 12)	25,116	10,657	25,074	10,644

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY/(DEFICIT)

(Unaudited)

(In thousands)

	Series A Preferred Stock	Common Stock	Warrants	Treasury Stock	Additional Paid-in-Capital	Retained Earnings	Total Stockholders Equity
Balance as of December 31, 2016 (Successor)	**$**	**$ 250**	**$ 37,329**	**$**	**$ 514,305**	**$ 9,930**	**$ 561,814**
Share-based compensation		1			8,518		8,519
Acquisition of treasury stock				(626)			(626)
Net income						35,890	35,890
Balance as of September 30, 2017 (Successor)	**$**	**$ 251**	**$ 37,329**	**$ (626)**	**$ 522,823**	**$ 45,820**	**$ 605,597**

	Series A Preferred Stock	Common Stock	Warrants	Treasury Stock	Additional Paid-in-Capital	Retained Deficit	Total Stockholders Deficit
Balance as of December 31, 2015 (Predecessor)	**$**	**$ 110**	**$**	**$ (3,081)**	**$ 888,247**	**$ (2,211,342)**	**$ (1,326,066)**
Share-based compensation		(1)			1,726		1,725
Acquisition of treasury stock				(53)			(53)
Net loss						(208,696)	(208,696)
Balance as of September 30, 2016 (Predecessor)	**$**	**$ 109**	**$**	**$ (3,134)**	**$ 889,973**	**$ (2,420,038)**	**$ (1,533,090)**

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Successor For the Nine Months Ended September 30, 2017	Predecessor For the Nine Months Ended September 30, 2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 35,890	$ (208,696)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gains on commodity derivative contracts net	(8,767)	
Net cash received for commodity derivative contracts not designated as hedging instruments	6,149	
Asset retirement accretion	833	1,316
Depreciation, depletion, and amortization	46,471	59,229
Impairment in carrying value of oil and gas properties		224,584
Share-based compensation, net of amounts capitalized to oil and gas properties	7,102	1,275
Amortization of deferred financing costs	277	4,495
Paid-in-kind interest expense		3,531
Amortization of deferred gain on debt restructuring		(8,246)
Operating lease abandonment		1,574
Noncash reorganization items		(70,489)
Change in operating assets and liabilities:		
Accounts receivable oil and gas sales	4,929	(311)
Accounts receivable JIB and other	2,641	21,411
Other current and noncurrent assets	(98)	(5,572)
Accounts payable	1,392	870
Accrued liabilities	(7,381)	54,520
Other	(121)	(1,247)
Net cash provided by operating activities	**$ 89,317**	**$ 78,244**
CASH FLOWS FROM INVESTING ACTIVITIES:		
Investment in property and equipment	$ (92,841)	$ (129,072)
Proceeds from the sale of oil and gas equipment and properties	4,235	
Net cash used in investing activities	**$ (88,606)**	**$ (129,072)**
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility		249,384
Deferred financing costs	(375)	
Acquisition of treasury stock	(626)	(53)
Net cash (used in) provided by financing activities	**$ (1,001)**	**$ 249,331**
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**$ (290)**	**$ 198,503**
Cash and cash equivalents, beginning of period	**$ 76,838**	**$ 81,093**
Cash and cash equivalents, end of period	**$ 76,548**	**$ 279,596**
SUPPLEMENTAL INFORMATION:		
Non-cash transactions investments in property and equipment accrued not paid	$ 19,865	$ 12,238
Cash paid for interest, net of capitalized interest of $2.1 million for the nine months ended September 30, 2017 (no capitalized interest for the nine months ended September 30, 2016)	$ 3,708	$ 5,821
Cash paid for reorganization items	$	$ 12,725

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

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MIDSTATES PETROLEUM COMPANY, INC.

Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Business

Midstates Petroleum Company, Inc. engages in the business of exploring and drilling for, and the production of, oil, natural gas liquids (NGLs) and natural gas in Oklahoma and Texas. Midstates Petroleum Company, Inc. was incorporated pursuant to the laws of the State of Delaware on October 25, 2011 to become a holding company for Midstates Petroleum Company LLC (Midstates Sub). The terms Company, we, us, our, similar terms refer to Midstates Petroleum Company, Inc. and its subsidiary.

The Company operates a significant portion of its oil and natural gas properties. The Company s management evaluates performance based on one reportable segment as all of its operations are located in the United States and, therefore, it maintains one cost center.

On April 30, 2016, the Company filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the Bankruptcy Court). The Company s Chapter 11 cases (the Chapter 11 Cases) were jointly administered under the case styled *In re Midstates Petroleum Company, Inc., et al., Case No. 16-32237.* On September 28, 2016, the Bankruptcy Court entered the *Findings of Fact, Conclusions of Law, and Order Confirming Debtors First Amended Joint Chapter 11 Plan of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate* (the Confirmation Order), which approved and confirmed the First Amended Joint Chapter 11 Plan of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate as filed on the same date (the Plan). On October 21, 2016 (the Effective Date), the Company satisfied the conditions to effectiveness set forth in the Confirmation Order and in the Plan, and, as a result, the Plan became effective in accordance with its terms and the Company emerged from the Chapter 11 Cases.

2. Summary of Significant Accounting Policies

Basis of Presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (US GAAP) for complete consolidated financial statements, and should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2016 included in the Company s Annual Report on Form 10-K as filed with the SEC on March 30, 2017.

All intercompany transactions have been eliminated in consolidation. In the opinion of the Company s management, the accompanying unaudited condensed consolidated financial statements include all adjustments, consisting of normal recurring adjustments, necessary to fairly present the financial position as of, and the results of operations for, all periods presented. In preparing the accompanying unaudited condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the unaudited condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852, *Reorganizations*, the Company adopted fresh start accounting upon emergence from the Chapter 11 Cases resulting in the Company becoming a new entity for financial reporting purposes. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, the Company s consolidated financial statements on or after October 21, 2016, are not comparable with the consolidated financial statements prior to that date. References to Successor Period relate to the results of operations for the period January 1, 2017 through September 30, 2017 and references to Predecessor Period refer to the results of operations from January 1, 2016 through September 30, 2016.

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Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASU 2014-09). ASU 2014-09 provides guidance concerning the recognition and measurement of revenue from contracts with customers. The objective of ASU 2014-09 is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. The Company has completed its review of contracts for each revenue stream identified within the Company s business and is currently finalizing its conclusion on any changes in revenue recognition upon adoption of the revised guidance. Based on assessments to date, the Company believes ASU 2014-09 will impact the presentation of future revenues and expenses by including certain transportation and gathering costs, along with various other fees such as compression and marketing fees net within revenues. The inclusion of these costs within revenues will not impact the Company s revenue recognition, its financial position, net income or cash flows. In addition, several industry interpretations are currently open for public comment. The Company cannot quantitatively assess the impact of ASU 2014-09 on its financial statements until final consensus is reached on these various industry matters. Once all pending industry interpretations are addressed, the Company will finalize its assessment of ASU 2014-09. The Company is in the process of evaluating the information technology and internal control changes that will be required for adoption based on the Company s contract review process, but does not currently anticipate material impacts to either information technology or internal controls. However, this assessment is pending conclusion of various industry interpretations. The Company intends to apply the modified retrospective approach upon adoption of this standard on the effective date of January 1, 2018.

In February 2016, the FASB issued Accounting Standards Update 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. All leases create an asset and a liability for the lessee and therefore recognition of those lease assets and lease liabilities is required by ASU 2016-02. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company is in the initial evaluation and planning stages for ASU 2016-02 and does not expect to move beyond this stage until completion of its evaluation of ASU 2014-09.

In July 2017, the FASB issued Accounting Standards Update 2017-11, *Earnings Per Share (Topic 260), Distinguishing Liabilities from Equity (Topic 480), and Derivatives and Hedging (Topic 815)* (ASU 2017-11). ASU 2017-11 changes the classification analysis of certain equity-linked financial instruments (or embedded features) with down round features. The amendments require entities that present earnings per share (EPS) in accordance with Topic 260 to recognize the effect of the down round feature when triggered with the effect treated as a dividend and as a reduction of income available to common shareholders in basic EPS. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company does not believe the adoption of ASU 2017-11 will have a material impact on its financial position, results of operations or cash flows.

3. Fair Value Measurements of Financial Instruments

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Derivative Instruments

Commodity derivative contracts reflected in the unaudited condensed consolidated balance sheets are recorded at estimated fair value. At September 30, 2017, all of the Company s commodity derivative contracts were with four bank counterparties and were classified as Level 2 in the fair value input hierarchy. The fair value of the Company s commodity derivatives are determined using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.

Derivative instruments listed below are presented gross and include swaps and collars that are carried at fair value. The Company records the net change in the fair value of these positions in Gains (losses) on commodity derivative contracts net in the Company s unaudited condensed consolidated statements of operations.

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	Fair Value Measurements at September 30, 2017			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Derivative Assets:				
Commodity derivative oil swaps	$	$ 722	$	$ 722
Commodity derivative gas swaps	$	$ 1,006	$	$ 1,006
Commodity derivative oil collars	$	$ 2,356	$	$ 2,356
Commodity derivative gas collars	$	$ 2,806	$	$ 2,806
Total assets	**$**	**$ 6,890**	**$**	**$ 6,890**
Derivative Liabilities:				
Commodity derivative oil swaps	$	$ (772)	$	$ (772)
Commodity derivative gas swaps	$	$	$	$
Commodity derivative oil collars	$	$ (1,380)	$	$ (1,380)
Commodity derivative gas collars	$	$ (2,120)	$	$ (2,120)
Total liabilities	**$**	**$ (4,272)**	**$**	**$ (4,272)**

At December 31, 2016, the Company did not have any open commodity derivative contract positions.

4. Risk Management and Derivative Instruments

The Company s production is exposed to fluctuations in crude oil, NGLs and natural gas prices. The Company believes it is prudent to manage the variability in cash flows by, at times, entering into derivative financial instruments to economically hedge a portion of its crude oil, NGLs and natural gas production. The Company utilizes various types of derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices.

- Swaps: The Company receives or pays a fixed price for the commodity and pays or receives a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Collars: A collar contains a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

- Three-way collars: A three-way collar contains a fixed floor price (long put), fixed sub-floor price (short put), and a fixed ceiling price (short call). If the market price exceeds the ceiling strike price, the Company receives the ceiling strike price and pays the market price. If the market price is between the ceiling and the floor strike price, no payments are due from either party. If the market price is below the floor price but above the sub-floor price, the Company receives the floor strike price and pays the market price. If the market price is below the sub-floor price, the

Company receives the market price plus the difference between the floor and the sub-floor strike prices and pays the market price.

These derivative contracts are placed with major financial institutions that the Company believes are minimal credit risks. The crude oil, NGLs and natural gas reference prices upon which the commodity derivative contracts are based reflect various market indices that management believes correlates with actual prices received by the Company for its crude oil, NGLs and natural gas production.

Inherent in the Company s portfolio of commodity derivative contracts are certain business risks, including market risk and credit risk. Market risk is the risk that the price of the commodity will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the Company s counterparty to a contract. The Company does not require collateral from its counterparties but does attempt to minimize its credit risk associated with derivative instruments by entering into derivative instruments only with counterparties that are large financial institutions, which management believes present minimal credit risk. In addition, to mitigate its risk of loss due to default, the Company has entered into agreements with its counterparties of its derivative instruments that allow the Company to offset its asset position with its liability position in the event of default by the counterparty. Due to the netting arrangements, had the Company s counterparties failed to perform under existing commodity derivative contracts, the maximum loss at September 30, 2017 would have been $2.6 million.

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Commodity Derivative Contracts

The Company has entered into various oil and natural gas derivative contracts that extend through March 2019, summarized as follows:

	NYMEX WTI								
	Fixed Swaps		Collars			Three Way Collars			
	Hedge Position (Bbls)	Weighted Avg Strike Price	Hedge Position (Bbls)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Hedge Position (Bbls)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Weighted Avg Sub-Floor Price
Quarter Ended:									
September 30, 2017(2)	207,000	$ 55.29	46,000	$ 60.00	$ 50.00	115,000	$ 62.80	$ 50.00	$ 40.00
December 31, 2017(1)(2)	276,000	$ 53.58	46,000	$ 60.00	$ 50.00	115,000	$ 62.80	$ 50.00	$ 40.00
March 31, 2018(1)	99,000	$ 50.61		$	$	225,000	$ 62.14	$ 50.00	$ 40.00
June 30, 2018(1)	145,600	$ 51.22		$	$	182,000	$ 60.65	$ 50.00	$ 40.00
September 30, 2018(1)	92,000	$ 50.38		$	$	184,000	$ 59.93	$ 50.00	$ 40.00
December 31, 2018(1)	92,000	$ 50.38		$	$	46,000	$ 56.70	$ 50.00	$ 40.00

	NYMEX HENRY HUB								
	Fixed Swaps		Collars			Three Way Collars			
	Hedge Position (MMBtu)	Weighted Avg Strike Price	Hedge Position (MMBtu)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Hedge Position (MMBtu)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Weighted Avg Sub-Floor Price
Quarter Ended:									
September 30, 2017	2,944,000	$ 3.38	368,000	$ 3.63	$ 3.15		$	$	$
December 31, 2017(1)	1,907,000	$ 3.43	551,000	$ 3.84	$ 3.23	610,000	$ 4.30	$ 3.25	$ 2.50
March 31, 2018(1)(3)	1,350,000	$ 3.47		$	$	1,530,000	$ 4.38	$ 3.25	$ 2.50
June 30, 2018(1)		$		$	$	1,365,000	$ 3.40	$ 3.00	$ 2.50
September 30, 2018(1)		$		$	$	1,380,000	$ 3.40	$ 3.00	$ 2.50
December 31, 2018(1)		$		$	$	1,380,000	$ 3.40	$ 3.00	$ 2.50
March 31, 2019(1)		$		$	$	1,350,000	$ 3.40	$ 3.00	$ 2.50

(1) Positions shown represent open commodity derivative contract positions as of September 30, 2017. The Company did not have any open commodity derivative contract positions as of December 31, 2016.

(2) During the second quarter, the Company entered into long call oil trades to offset its three way collar short calls for the second half of 2017.

(3) During the second quarter, the Company entered into natural gas three way collars with long call ceilings in order to offset its Q1 2018 natural gas fixed swaps.

Subsequent to September 30, 2017, the Company entered into various oil derivative contracts that extend through December 2019, summarized as follows:

	NYMEX WTI								
	Fixed Swaps		Collars			Three Way Collars			
	Hedge Position (Bbls)	Weighted Avg Strike Price	Hedge Position (Bbls)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Hedge Position (Bbls)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Weighted Avg Sub-Floor Price
Quarter Ended:									
March 31, 2019		$		$	$	45,000	$ 56.20	$ 50.00	$ 40.00
June 30, 2019		$		$	$	45,500	$ 56.20	$ 50.00	$ 40.00
September 30, 2019		$		$	$	46,000	$ 56.20	$ 50.00	$ 40.00
December 31, 2019		$		$	$	46,000	$ 56.20	$ 50.00	$ 40.00

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Balance Sheet Presentation

The following table summarizes the net fair values of commodity derivative instruments by the appropriate balance sheet classification in the Company s unaudited condensed consolidated balance sheets at September 30, 2017 (in thousands):

Type	**Balance Sheet Location (1)**		**September 30, 2017**
Oil swaps	Derivative financial instruments current assets	$	49
Gas swaps	Derivative financial instruments current assets		1,006
Oil collars	Derivative financial instruments current assets		969
Gas collars	Derivative financial instruments current assets		872
Oil swaps	Derivative financial instruments noncurrent liabilities		(98)
Oil collars	Derivative financial instruments noncurrent liabilities		6
Gas collars	Derivative financial instruments noncurrent liabilities		(186)
Total derivative fair value at period end		**$**	**2,618**

(1) The fair values of commodity derivative instruments reported in the Company s unaudited condensed consolidated balance sheets are subject to netting arrangements and qualify for net presentation.

The following table summarizes the location and fair value amounts of all commodity derivative instruments in the unaudited condensed consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the unaudited condensed consolidated balance sheets at September 30, 2017 (in thousands):

			September 30, 2017					
Not Designated as ASC 815 Hedges	**Balance Sheet Location Classification**			**Gross Recognized Assets/Liabilities**		**Gross Amounts Offset**		**Net Recognized Fair Value Assets/Liabilities**
Derivative Assets:								
Commodity contracts	Derivative financial instruments	current	$	5,858	$	(2,962)	$	2,896
Commodity contracts	Derivative financial instruments	noncurrent		1,032		(1,032)		
			$	**6,890**	**$**	**(3,994)**	**$**	**2,896**
Derivative Liabilities:								
Commodity contracts	Derivative financial instruments	current	$	(2,962)	$	2,962	$	
Commodity contracts	Derivative financial instruments	noncurrent		(1,310)		1,032		(278)
			$	**(4,272)**	**$**	**3,994**	**$**	**(278)**

As of December 31, 2016, the Company did not have any open commodity derivative contract positions.

Gains/Losses on Commodity Derivative Contracts

The Company does not designate its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, commodity derivative contracts are marked-to-market each quarter with the change in fair value during the periodic reporting period recognized currently as a gain or loss in Gains (losses) on commodity derivative contracts net within revenues in the unaudited condensed consolidated statements of operations.

The following table presents net cash received for commodity derivative contracts and unrealized net gains recorded by the Company related to the change in fair value of the derivative instruments in Gains (losses) on commodity derivative contracts net for the periods presented (in thousands):

	For the Three Months Ended September 30, 2017	For the Nine Months Ended September 30, 2017
Net cash received for commodity derivative contracts	$ 2,909	$ 6,149
Unrealized net (losses) gains	(6,500)	2,618
Gains (losses) on commodity derivative contracts net	**$ (3,591)**	**$ 8,767**

Cash settlements, as presented in the table above, represent realized gains related to the Company s derivative instruments. In addition to cash settlements, the Company also recognizes fair value changes on its derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves.

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5. Property and Equipment

Property and equipment consisted of the following as of the dates presented:

	September 30, 2017		December 31, 2016	
	(in thousands)			
Oil and gas properties, on the basis of full-cost accounting:				
Proved properties	$	709,647	$	573,150
Unproved properties		26,178		65,080
Other property and equipment		6,543		6,339
Less accumulated depreciation, depletion and amortization		(59,349)		(12,974)
Net property and equipment	**$**	**683,019**	**$**	**631,595**

Oil and Gas Properties

The Company capitalizes internal costs directly related to exploration and development activities to oil and gas properties. During the three and nine months ended September 30, 2017 and 2016, the Company capitalized the following (in thousands):

	Successor Three Months Ended September 30, 2017		Predecessor Three Months Ended September 30, 2016		Successor Nine Months Ended September 30, 2017		Predecessor Nine Months Ended September 30, 2016	
Internal costs capitalized to oil and gas properties (1)	$	1,651	$	1,049	$	4,656	$	3,311

(1) Inclusive of $0.8 million and $0.1 million of qualifying share-based compensation expense for the three months ended September 30, 2017 and 2016, respectively. For the nine months ended September 30, 2017 and 2016, inclusive of $2.0 million and $0.5 million, respectively, of qualifying share-based compensation expense.

The Company accounts for its oil and gas properties under the full cost method. Under the full cost method, proceeds realized from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion of the Company s reserve quantities are sold such that it results in a significant alteration of the relationship between capitalized costs and remaining proved reserves, in which case a gain or loss is generally recognized in income. During the nine months ended September 30, 2017, the Company disposed of certain oil and gas equipment for cash proceeds of $1.4 million, which were reflected as a reduction of oil and gas properties with no gain or loss recognized. During the three months ended September 30, 2017, the Company closed on the sale of certain oil and gas properties in Lincoln County, Oklahoma, for $7.0 million in cash ($2.9 million, net after assumption of liabilities), subject to standard post-closing adjustments. The net proceeds from the sale were retained for general corporate purposes.

The Company performs a full-cost ceiling test on a quarterly basis. The test establishes a limit (ceiling) on the book value of the Company s oil and gas properties. The capitalized costs of oil and gas properties, net of accumulated depreciation, depletion, amortization and impairment (DD&A) and the related deferred income taxes, may not exceed this ceiling. The ceiling limitation is equal to the sum of: (i) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet, calculated using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged to expense in the accompanying unaudited condensed consolidated statements of operations.

The Company did not record an impairment of oil and gas properties during the three or nine months ended September 30, 2017. The three and nine month periods ended September 30, 2016 included impairments of oil and gas properties of $33.9 million and $224.6 million, respectively. These impairments were primarily the result of continued low commodity prices, which resulted in a decrease in the discounted present value of the Company s proved oil and natural gas reserves.

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DD&A is calculated using the Units of Production Method (UOP). The UOP calculation multiplies the percentage of total estimated proved reserves produced by the cost of those reserves. The result is to recognize expense at the same pace that the reservoirs are estimated to be depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated DD&A and impairment, estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value. The following table presents depletion expense related to oil and gas properties for the three and nine months ended September 30, 2017 and 2016, respectively:

	Successor	Predecessor	Successor	Predecessor	Successor	Predecessor	Successor	Predecessor
	Three Months Ended September 30,		**Three Months Ended September 30,**		**Nine Months Ended September 30,**		**Nine Months Ended September 30,**	
	2017	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
	(in thousands)		**(per Boe)**		**(in thousands)**		**(per Boe)**	
Depletion expense	$ 14,575	$ 15,231	$ 7.42	$ 5.90	$ 44,695	$ 57,018	$ 7.29	$ 6.92
Depreciation on other property and equipment	595	525	0.30	0.20	1,776	2,211	0.29	0.27
Depreciation, depletion, and amortization	**$ 15,170**	**$ 15,756**	**$ 7.72**	**$ 6.10**	**$ 46,471**	**$ 59,229**	**$ 7.58**	**$ 7.19**

Oil and gas unproved properties include costs that are not being depleted or amortized. The Company excludes these costs until proved reserves are found, until it is determined that the costs are impaired or until major development projects are placed in service, at which time the costs are moved into oil and natural gas properties subject to amortization. All unproved property costs are reviewed at least annually to determine if impairment has occurred. In addition, impairment assessments are made for interim reporting periods if facts and circumstances exist that suggest impairment may have occurred. During any period in which impairment is indicated, the accumulated costs associated with the impaired property are transferred to proved properties and become part of our depletion base and subject to the full cost ceiling limitation. No impairment of unproved properties was recorded during the three or nine months ended September 30, 2017. Unproved property was $26.2 million and $65.1 million at September 30, 2017 and December 31, 2016, respectively.

Other Property and Equipment

Other property and equipment consists of vehicles, furniture and fixtures, and computer hardware and software and are carried at cost. Depreciation is calculated principally using the straight-line method over the estimated useful lives of the assets, which range from five to seven years. Maintenance and repairs are charged to expense as incurred, while renewals and betterments are capitalized.

6. Other Noncurrent Assets

The following table presents the components of other noncurrent assets as of the dates presented:

	September 30, 2017	December 31, 2016
	(in thousands)	

Deferred financing costs associated with the Exit Facility	$	1,286	$	1,187
Field equipment inventory		4,221		2,619
Other		1,649		1,649
Other noncurrent assets	**$**	**7,156**	**$**	**5,455**

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7. Accrued Liabilities

The following table presents the components of accrued liabilities as of the dates presented:

	September 30, 2017		December 31, 2016	
	(in thousands)			
Accrued oil and gas capital expenditures	$	12,281	$	6,118
Accrued revenue and royalty distributions		17,707		28,262
Accrued lease operating and workover expense		6,200		8,932
Accrued interest		123		254
Accrued taxes		2,980		2,537
Compensation and benefit related accruals		5,133		3,516
Other		2,563		4,112
Accrued liabilities	**$**	**46,987**	**$**	**53,731**

8. Asset Retirement Obligations

Asset Retirement Obligations (AROs) represent the estimated future abandonment costs of tangible assets, such as wells, service assets and other facilities. The estimated fair value of the AROs at inception is capitalized as part of the carrying amount of the related long-lived assets.

The following table reflects the changes in the Company s AROs for the periods presented (in thousands):

	Successor Nine Months Ended September 30, 2017		Predecessor Nine Months Ended September 30, 2016	
Asset retirement obligations beginning of period	$	14,200	$	18,708
Liabilities incurred		259		520
Revisions				
Liabilities settled		(107)		(278)
Liabilities eliminated through asset sales		(1,146)		
Current period accretion expense		833		1,316
Asset retirement obligations end of period	**$**	**14,039**	**$**	**20,266**

9. Debt

Exit Facility

At September 30, 2017 and December 31, 2016, the Company maintained a reserves based credit facility with a borrowing base of $170.0 million (the Exit Facility). At September 30, 2017, and December 31, 2016, the Company had $128.1 million drawn on the Exit Facility and had outstanding letters of credit obligations totaling $1.9 million. As of September 30, 2017, the Company had $40.0 million of availability on the Exit Facility.

The Exit Facility bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. For the three months ended September 30, 2017, the weighted average interest rate was 5.7%. Unamortized debt issuance costs of $1.3 million and $1.2 million associated with the Exit Facility are included in Other noncurrent assets on the unaudited condensed consolidated balance sheets at September 30, 2017, and December 31, 2016, respectively.

In addition to interest expense, the Exit Facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of 0.50% per annum based on the average daily amount by which the borrowing base exceeds outstanding borrowings during each quarter.

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On May 24, 2017, the Company entered into the First Amendment to the Exit Facility (the First Amendment). The First Amendment, among other items, (i) moved the first scheduled borrowing base redetermination from April 2018 to October 2017; (ii) removed the requirement to maintain a cash collateral account with the administrative agent in the amount of $40.0 million; (iii) removed the requirement to maintain at least 20% liquidity of the then effective borrowing base; (iv) amended the required mortgage threshold from 95% to 90%; (v) amended the threshold amount for which the borrower is required to provide advance notice to the administrative agent of a sale or disposition of oil and gas properties which occurs during the period between two successive redeterminations of the borrowing base; (vi) amended the required ratio of total net indebtedness to EBITDA from 2.25:1.00 to 4.00:1.00; (vii) amended the required EBITDA to interest coverage ratio from not less than 3.00:1.00 to not less than 2.50:1.00; and (viii) removed certain limitations on capital expenditures.

As of September 30, 2017, the Company was in compliance with its debt covenants.

On October 27, 2017, the Company s borrowing base was redetermined at the existing amount of $170.0 million. The Company s Anadarko Basin assets in Texas and Oklahoma were excluded from the redetermination of the borrowing base.

The Company believes the carrying amount of the Exit Facility at September 30, 2017 approximates its fair value (Level 2) due to the variable nature of the Exit Facility interest rate.

10. Equity and Share-Based Compensation

Common Shares

Share Activity

The following table summarizes changes in the number of outstanding shares during the nine months ended September 30, 2017:

	Common Stock	Treasury Stock(1)
Share count as of December 31, 2016	**24,994,867**	
Common stock issued	103,967	
Acquisition of treasury stock		(33,409)
Share count as of September 30, 2017	**25,098,834**	(33,409)

(1) Treasury stock represents the net settlement on vesting of restricted stock necessary to satisfy the minimum statutory tax withholding requirements.

Share-Based Compensation

2016 Long Term Incentive Plan

On the Effective Date, the Company established the 2016 LTIP and filed a Form S-8 with the SEC, registering 3,513,950 shares for issuance under the terms of the 2016 LTIP to employees, directors and certain other persons (the Award Shares). The types of awards that may be granted under the 2016 LTIP include stock options, restricted stock units, restricted stock, performance awards and other forms of awards granted or denominated in shares of common stock of the reorganized Company, as well as certain cash-based awards (the Awards). The terms of each award are as determined by the Compensation Committee of the Board of Directors. Awards that expire, or are canceled, forfeited, exchanged, settled in cash or otherwise terminated, will again be available for future issuance under the 2016 LTIP. At September 30, 2017, 2,299,088 Award Shares remain available for issuance under the terms of the 2016 LTIP.

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Restricted Stock Units

At September 30, 2017, the Company had 494,794 non-vested restricted stock units outstanding to employees and non-employee directors pursuant to the 2016 LTIP, excluding restricted stock units issued to non-employee directors containing a market condition, which are discussed below. Restricted stock units granted to employees under the 2016 LTIP vest ratably over a period of three years: one-sixth will vest on the six-month anniversary of the grant date, an additional one-sixth will vest on the twelve-month anniversary of the grant date, an additional one-third will vest on the twenty-four month anniversary of the grant date and the final one-third will vest on the thirty-six month anniversary of the grant date. Restricted stock units granted to non-employee directors vest on the first to occur of (i) December 31, 2017, (ii) the date the non-employee director ceases to be a director of the Board (other than for cause), (iii) the director s death, (iv) the director s disability or (v) a change in control of the Company.

The fair value of restricted stock units was based on grant date fair value of the Company s common stock. Compensation expense is recognized ratably over the requisite service period.

The following table summarizes the Company s non-vested restricted stock unit award activity for the nine months ended September 30, 2017:

	Restricted Stock		Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2016	**685,662**	$	19.66
Granted	17,500	$	18.62
Vested	(103,967)	$	19.66
Forfeited	(104,401)	$	19.66
Non-vested shares outstanding at September 30, 2017	**494,794**	$	19.63

Unrecognized expense as of September 30, 2017, for all outstanding restricted stock units under the 2016 LTIP was $3.9 million and will be recognized over a weighted average period of 1.2 years. Subsequent to September 30, 2017, 174,135 restricted stock units vested before consideration of minimum statutory tax withholding requirements.

On August 22, 2017, the Company amended the employment agreement of Fredric F. Brace, former President and Chief Executive Officer (the Executive Employment Amendment). Among other provisions, the Executive Employment Amendment accelerated the vesting of all outstanding equity awards of Mr. Brace to October 21, 2017. As a result, approximately $0.8 million of compensation expense associated with Mr. Brace s non-vested restricted stock was accelerated into the three and nine months ended September 30, 2017.

Stock Options

At September 30, 2017, the Company had 423,438 non-vested stock options outstanding pursuant to the 2016 LTIP. Stock Option Awards granted under the 2016 LTIP vest ratably over a period of three years: one-sixth will vest on the six-month anniversary of the grant date, an additional one-sixth will vest on the twelve-month anniversary of the grant date, an additional one-third will vest on the twenty-four month anniversary of the grant date and the final one-third will vest on the thirty-six month anniversary of the grant date. Stock Option Awards expire 10 years from the grant date.

The Company utilizes the Black-Scholes-Merton option pricing model to determine the fair value of stock option awards. Determining the fair value of equity-based awards requires judgment, including estimating the expected term that stock option awards will be outstanding prior to exercise and the associated volatility.

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The following table summarizes the Company s 2016 LTIP non-vested stock option activity for the nine months ended September 30, 2017:

	Options		Range of Exercise Prices		Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)
Stock options outstanding at December 31, 2016	627,806			$	19.66	9.1
Granted	4,000	$	19.08	$	19.08	9.5
Vested	(103,967)	$	19.08-20.97	$	19.66	
Forfeited	(104,401)	$	19.66	$	19.66	
Stock options outstanding at September 30, 2017	423,438			$	19.66	9.1
Vested and exercisable at end of period(1)	103,967	$	19.08-20.97	$	19.66	9.1

(1) Vested and exercisable options at September 30, 2017, had no aggregate intrinsic value.

Unrecognized expense as of September 30, 2017, for all outstanding stock options under the 2016 LTIP was $1.9 million and will be recognized over a weighted average period of 1.3 years. Subsequent to September 30, 2017, 171,885 stock options vested before consideration of minimum statutory tax withholding requirements.

On August 22, 2017, the Company amended the Executive Employment Amendment. Among other provisions, the Executive Employment Amendment accelerated the vesting of all outstanding equity awards of Mr. Brace to October 21, 2017. As a result, approximately $0.4 million of compensation expense associated with Mr. Brace s non-vested stock options was accelerated into the three and nine months ended September 30, 2017.

Non-Employee Director Restricted Stock Units Containing a Market Condition

On November 23, 2016, the Company issued certain restricted stock units to non-employee directors that contain a market vesting condition. These restricted stock units will vest (i) on the first business day following the date on which the trailing 60-day average share price (including any dividends paid) of the Company s common stock is equal to or greater than $30.00 or (ii) upon a change in control of the Company. Additionally, all unvested restricted stock units containing a market vesting condition will be immediately forfeited upon the first to occur of (i) the fifth (5th) anniversary of the grant date or (ii) any participant s termination as a director for any reason (except for a termination as part of a change in control of the Company).

These restricted stock awards are accounted for as liability awards under FASB ASC 718 as the awards allow for the withholding of taxes at the discretion of the non-employee director. The liability is re-measured, with a corresponding adjustment to earnings, at each fiscal quarter-end during the performance cycle. The liability and related compensation expense of these awards for each period is recognized by dividing the fair value of the total liability by the requisite service period and recording the pro rata share for the period for which service has already been provided. As there are inherent uncertainties related to these factors and the Company s judgment in applying them to the fair value determinations, there is risk that the recorded compensation may not accurately reflect the amount ultimately earned by the non-employee directors.

The restricted stock unit awards issued to non-employee directors containing a market condition has a derived service period of one year. At September 30, 2017, the Company recorded a $0.7 million liability included within Accrued liabilities in the unaudited condensed consolidated balance sheets related to the market condition awards. The fair value of the restricted stock containing a market condition was $11.05 per unit at September 30, 2017.

As of September 30, 2017, unrecognized stock-based compensation related to market condition awards was $0.1 million and will be recognized over a weighted-average period of 0.1 years.

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11. Income Taxes

For the nine months ended September 30, 2017, the Company recorded no income tax expense or benefit. The significant difference between our effective tax rate and the federal statutory income tax rate of 35% is primarily due to the effect of changes in the Company s valuation allowance. During the nine months ended September 30, 2017, the Company s valuation allowance decreased by $13.0 million from December 31, 2016, bringing the total valuation allowance to $147.8 million at September 30, 2017. A valuation allowance has been recorded as management does not believe that it is more-likely-than-not that its deferred tax assets are realizable.

The Company expects to incur a tax loss in the current year due to the flexibility in deducting or capitalizing current year intangible drilling costs; thus no current income taxes are anticipated to be paid.

12. Earnings (Loss) Per Share

Successor

The following table provides a reconciliation of net income attributable to common shareholders and weighted average common shares outstanding for basic and diluted earnings per share for the Successor Periods presented:

	Three Months Ended September 30, 2017 (in thousands, except per share amounts)		Nine Months Ended September 30, 2017 (in thousands, except per share amounts)	
Net Earnings:				
Net income	$	3,663	$	35,890
Participating securities non-vested restricted stock		(82)		(932)
Basic and diluted earnings	**$**	**3,581**	**$**	**34,958**
Common Shares:				
Common shares outstanding basic (1)		**25,116**		**25,074**
Dilutive effect of potential common shares				
Common shares outstanding diluted		**25,116**		**25,074**
Net Earnings Per Share:				
Basic	**$**	**0.14**	**$**	**1.39**
Diluted	**$**	**0.14**	**$**	**1.39**
Antidilutive stock options (2)		**424**		**526**
Antidilutive warrants (3)		**6,626**		**6,626**

(1) Weighted-average common shares outstanding for basic and diluted earnings per share purposes includes 17,533 shares of common stock that, while not issued and outstanding at September 30, 2017, are required by the Plan to be issued.

(2) Amount represents stock options to purchase common stock that are excluded from the diluted net earnings per share calculations because of their antidilutive effect.

(3) Amount represents warrants to purchase common stock that are excluded from the diluted net earnings per share calculations because of their antidilutive effect.

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Predecessor

The Company s nonvested stock awards, which were granted as part of the 2012 LTIP, contained nonforfeitable rights to dividends and as such, were considered to be participating securities and are included in the computation of basic and diluted earnings per share, pursuant to the two-class method.

The computation of diluted earnings per share attributable to common shareholders reflects the potential dilution that could occur if securities or other contracts to issue common shares that are dilutive were exercised or converted into common shares (or resulted in the issuance of common shares) and would then share in the earnings of the Company. During the periods in which the Company records a loss from continuing operations attributable to common shareholders, securities would not be dilutive to net loss per share and conversion into common shares is assumed to not occur. Diluted net earnings (loss) per share attributable to common shareholders is calculated under both the two-class method and the treasury stock method; the more dilutive of the two calculations is presented below.

The following table provides a reconciliation of net loss to preferred shareholders, common shareholders, and participating securities for purposes of computing net loss per share for the Predecessor Periods presented:

	Three Months Ended September 30, 2016 (in thousands, except per share amounts)	Nine Months Ended September 30, 2016 (in thousands, except per share amounts)
Net loss	$ (38,384)	$ (208,696)
Preferred Dividend		
Participating securities non-vested restricted stock		
Net loss attributable to shareholders	**$ (38,384)**	**$ (208,696)**
Weighted average shares outstanding	**10,657**	**10,644**
Basic and diluted net loss per share	**$ (3.60)**	**$ (19.61)**

13. Related Party Transactions

The Company has entered into an arrangement with EcoStim Energy Solutions, Inc. (EcoStim) for well stimulation and completion services. EcoStim is an affiliate of Fir Tree Inc., an entity holding approximately 25.5% of the Company s outstanding common stock. For the three and nine months ended September 30, 2017, the Company paid approximately $5.9 million and $7.3 million, respectively, to EcoStim for services provided. No transactions with EcoStim occurred during the three and nine months ended September 30, 2016.

14. Commitments and Contingencies

The Company is involved in various matters incidental to its operations and business that might give rise to a loss contingency. These matters may include legal and regulatory proceedings, commercial disputes, claims from royalty, working interest and surface owners, property damage and personal injury claims and environmental or other matters. In addition, the Company may be subject to customary audits by governmental authorities regarding the payment and reporting of various taxes, governmental royalties and fees as well as compliance with unclaimed property (escheatment) requirements and other laws. Further, other parties with an interest in wells operated by the Company have the ability under various contractual agreements to perform audits of its joint interest billing practices.

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The Company vigorously defends itself in these matters. If the Company determines that an unfavorable outcome or loss of a particular matter is probable and the amount of loss can be reasonably estimated, it accrues a liability for the contingent obligation. As new information becomes available or as a result of legal or administrative rulings in similar matters or a change in applicable law, the Company s conclusions regarding the probability of outcomes and the amount of estimated loss, if any, may change. The impact of subsequent changes to the Company s accruals could have a material effect on its results of operations. As of September 30, 2017, and December 31, 2016, the Company s total accrual for all loss contingencies was $1.4 million and $1.1 million, respectively.

During the nine months ended September 30, 2017, the Company received an insurance reimbursement in the amount of $1.9 million, which was reflected as a reduction of Lease operating and workover expenses in the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2017.

15. Subsequent Event

On October 25, 2017, David J. Sambrooks was appointed to the position of President and Chief Executive Officer, effective immediately upon the resignation of Mr. Brace on November 1, 2017. The Board of Directors of the Company (the Board) also approved an increase in the number of directors, from seven directors to eight directors, and Mr. Sambrooks was appointed to the Board, effective concurrently with his appointment as an executive officer.

In connection with the appointment of Mr. Sambrooks as President and Chief Executive Officer, Mr. Sambrooks and the Company entered into an employment agreement outlining the terms of his employment as President and Chief Executive Officer of the Company. Among other provisions, Mr. Sambrooks received incentive awards including (i) the grant of 67,889 time-vested restricted stock units and (ii) the grant of 135,778 performance stock units (PSUs). The time-vested restricted stock units will generally vest in three installments: 1/3 will vest on the one-year anniversary of the award date, an additional 1/3 will vest on the two-year anniversary of the award date and the final 1/3 will vest on the three-year anniversary of the award date. The PSUs will vest, if at all, based upon the performance of the Company s stock during the period of October 25, 2017 through October 31, 2020 (the Performance Period). Half of the PSUs will vest, if at all, based upon the Company s total absolute stockholder return for the Performance Period, and the other half will vest, if at all, based upon the Company s relative total stockholder return when measuring the Company s stock performance during the Performance Period to the stock performance of a selected peer group during the Performance Period.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto for the year ended December 31, 2016, and the related management s discussion and analysis contained in our Annual Report on Form 10-K dated and filed with the Securities and Exchange Commission (SEC) on March 30, 2017, as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the Securities Act) and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act). All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, and the plans, beliefs, expectations, intentions and objectives of management are forward-looking statements. When used in this Quarterly Report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project, a are intended to identify forward looking statements, although not all forward looking statements contain such identifying words. All forward-looking statements speak only as of the date of this Quarterly Report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this report and in the Annual Report on Form 10-K. Moreover, we operate in a very competitive and rapidly changing environment. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy, including our business strategy post-emergence from our Chapter 11 Cases;
- estimated future net reserves and present value thereof;
- technology;
- financial condition, revenues, cash flows and expenses;
- levels of indebtedness, liquidity, borrowing capacity and compliance with debt covenants;

- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability of oilfield labor;
- availability of third party natural gas gathering and processing capacity;
- availability and terms of capital;
- drilling of wells, including our identified drilling locations;
- successful results from our identified drilling locations;
- marketing of oil and natural gas;
- the integration and benefits of asset and property acquisitions or the effects of asset and property acquisitions or dispositions on our cash position and levels of indebtedness;
- infrastructure for salt water disposal and electricity;
- current and future ability to dispose of salt water;
- sources of electricity utilized in operations and the related infrastructures;
- costs of developing our properties and conducting other operations;
- general economic conditions;

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- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- the outcome of pending and future litigation;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil and natural gas producing countries;
- new capital structure and the adoption of fresh start accounting, including the risk that assumptions and factors used in estimating enterprise value vary significantly from the current estimates in connection with the application of fresh start accounting;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical.

Overview

We are an independent exploration and production company focused on the application of modern drilling and completion techniques in oil and liquids-rich basins in the onshore United States. Our operations are primarily focused on exploration and production activities in the Mississippian Lime and Anadarko Basin. The terms Company, we, us, our, and similar terms refer to us and our subsidiary, unless the context indicates otherwise.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we realize from the sale of that production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, if any, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials, and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

Upon our emergence from the Chapter 11 Cases on October 21, 2016, we adopted fresh start accounting as required by US GAAP. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements on or after October 21, 2016, are not comparable with our consolidated financial statements prior to that date. References to Successor Period relate to the results of operations for the period January 1, 2017 through September 30, 2017 and references to Predecessor Period refer to the results of operations of the Company from January 1, 2016 through September 30, 2016.

Operations Update

Mississippian Lime

For the three months ended September 30, 2017 and June 30, 2017, our average daily production from the Mississippian Lime asset was as follows:

	Three Months Ended September 30, 2017	Three Months Ended June 30, 2017	Increase/(Decrease) in Production
Average daily production:			
Oil (Bbls)	4,940	4,938	%
Natural gas liquids (Bbls)	4,145	4,466	(7.2)%
Natural gas (Mcf)	51,130	53,246	(4.0)%
Net Boe/day	**17,606**	**18,278**	**(3.7)%**

The following table shows our total number of horizontal wells spud and brought into production in the Mississippian Lime asset during the third quarter of 2017:

	Total Number of Gross Horizontal Wells Spud (1)	Total Number of Gross Horizontal Wells Brought into Production
Mississippian Lime	10	9

(1) We had two rigs drilling in the Mississippian Lime horizontal well program at September 30, 2017. Of the ten wells spud, three were producing, five were awaiting completion and two were being drilled at quarter-end.

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In the third quarter of 2017, we incurred approximately $39.8 million of operational capital expenditures in the Mississippian Lime basin.

Anadarko Basin

For the three months ended September 30, 2017 and June 30, 2017, our average daily production from our Anadarko Basin asset was as follows:

	Three Months Ended September 30, 2017	Three Months Ended June 30, 2017	Decrease in Production
Average daily production:			
Oil (Bbls)	1,329	1,475	(9.9)%
Natural gas liquids (Bbls)	992	1,115	(11.0)%
Natural gas (Mcf)	8,581	9,735	(11.9)%
Net Boe/day	**3,752**	**4,212**	(10.9)%

We did not spud any wells in our Anadarko Basin asset and did not have any operated drilling rigs in the area during the third quarter of 2017.

Capital Expenditures

During the three and nine months ended September 30, 2017, we incurred operational capital expenditures of $40.1 million and $97.7 million, respectively, which consisted of the following:

	For the Three Months Ended September 30, 2017	For the Nine Months Ended September 30, 2017
Drilling and completion activities	$ 36,269	$ 89,975
Acquisition of acreage and seismic data	3,845	7,748
Operational capital expenditures incurred	**$ 40,114**	**$ 97,723**
Capitalized G&A, office, ARO & other	1,856	5,512
Capitalized interest	408	2,054
Total capital expenditures incurred	**$ 42,378**	**$ 105,289**

Operational capital expenditures by area were as follows:

	For the Three Months Ended	For the Nine Months Ended

	September 30, 2017	September 30, 2017
Mississippian Lime	$ 39,800	$ 95,490
Anadarko Basin	314	2,233
Total operational capital expenditures incurred	**$ 40,114**	**$ 97,723**

We are currently operating two drilling rigs in the Mississippian Lime asset. Based upon a two rig program, we would expect to invest between $130.0 million to $140.0 million of capital for exploration, development and lease and seismic acquisition, and drill 36 to 40 gross wells during the year ended December 31, 2017.

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Factors that Significantly Affect Our Risk

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from any given well is expected to decline. As a result, oil and natural gas exploration and production companies deplete their asset base with each unit of oil or natural gas they produce. We attempt to overcome this natural production decline by developing additional reserves through our drilling operations, acquiring additional reserves and production and implementing secondary recovery techniques. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on the capital investments necessary to produce our reserves as well as to add to our reserves through drilling and acquisition. Our ability to make the necessary capital expenditures is dependent on cash flow from operations as well as our ability to obtain additional debt and equity financing. That ability can be limited by many factors, including the cost and terms of such capital, our current financial condition, expectations regarding the future price for oil and natural gas, and operational considerations.

The volumes of oil and natural gas that we produce are driven by several factors, including:

- success in the drilling of new wells, including exploratory wells, and the recompletion or workover of existing wells;
- the amount of capital we invest in the leasing and development of our oil and natural gas properties;
- facility or equipment availability and unexpected downtime;
- delays imposed by or resulting from compliance with regulatory requirements;
- the rate at which production volumes on our wells naturally decline; and
- our ability to economically dispose of salt water produced in conjunction with our production of oil and gas.

We follow the full cost method of accounting for our oil and gas properties. For the three and nine months ended September 30, 2017, the results of our full cost ceiling test did not require us to recognize impairments of our oil and gas properties. While impairments do not impact cash flow from operating activities or liquidity, they do decrease our net income and shareholders equity.

We dispose of large volumes of saltwater produced in conjunction with crude oil and natural gas from drilling and production operations in the Mississippian Lime. Our disposal operations are conducted pursuant to permits issued to us by governmental authorities overseeing such disposal activities.

There is a continuing concern and regulatory scrutiny surrounding any potential correlation between the injection of saltwater into disposal wells and those activities alleged contribution to increased seismic activity in certain areas, including the areas in which we operate, Oklahoma and Texas. On February 16, 2016, the Oil and Gas Conservation Division (OGCD) of the Oklahoma Corporation Commission (OCC) requested we curtail our wastewater disposal volumes into the Arbuckle formation in our Mississippian Lime assets by approximately 40%. On March 7, 2016 and August 19, 2016, the OGCD identified additional wells that were required to reduce disposal volume. The OGCD established caps for additional wells on February 24, 2017. On March 1, 2017, the OGCD also issued a statement saying that further actions to reduce the earthquake rate in Oklahoma could be expected. Our current plans are for future disposal wells to inject into formations other than the Arbuckle and we are currently disposing of approximately 40% of our produced salt water into formations other than the Arbuckle. We have timely met and satisfied all requests of the OCC regarding changes and/or reductions in disposal capacity in our operated Arbuckle disposal wells, and now inject at a rate which is approximately 20% below the OGCD s prescribed limits for the Arbuckle formation without adverse impact to our production base. We are currently in compliance with the OGCD s latest requests regarding Arbuckle injection limits; however a change in disposal well regulations or injection limits, or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of salt water and ultimately increase the cost of our operations and/or reduce the volume of oil and natural gas that we produce from our wells.

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Under Rule 4-10(a)(22) of Regulation S-X, as promulgated by the SEC, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Our customary practice is at each fiscal year end our technical team meets with representatives of our independent reserves engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. We maintain an internal staff of petroleum engineers, land and geoscience professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timeliness of data utilized in the reserves estimation process. The primary inputs to the reserves estimation process are comprised of technical information, financial data, ownership interests and production data. The valuation of our proved reserves is sensitive to changes in these inputs and, as a result, minor updates to these inputs can result in significant changes in the valuation of such reserves. The extent of any such changes in reserves valuation is inherently uncertain until the final completion of the proved reserves estimates at each fiscal year end.

Results of Operations

The following tables summarize our revenues for the three and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30,			
	Crude Oil	Natural Gas	NGLs	Total
2016 Revenues (Predecessor)	$ 35,584	$ 17,676	$ 8,939	$ 62,199
Changes due to volumes	(11,820)	(3,776)	(2,649)	(18,245)
Changes due to price	3,426	70	4,366	7,862
2017 Revenues (Successor)	$ 27,190	$ 13,970	$ 10,656	$ 51,816

	Nine Months Ended September 30,			
	Crude Oil	Natural Gas	NGLs	Total
2016 Revenues (Predecessor)	$ 104,832	$ 44,486	$ 25,073	$ 174,391
Changes due to volumes	(48,583)	(12,776)	(6,717)	(68,076)
Changes due to price	29,248	14,611	13,224	57,083
2017 Revenues (Successor)	$ 85,497	$ 46,321	$ 31,580	$ 163,398

Oil, NGL and Natural Gas Pricing

The following table sets forth information regarding average realized sales prices for the periods indicated:

	Successor For the Three Months Ended September 30, 2017	Predecessor For the Three Months Ended September 30, 2016	% Change	Successor For the Nine Months Ended September 30, 2017	Predecessor For the Nine Months Ended September 30, 2016	% Change
AVERAGE SALES PRICES:						
Oil, without realized derivatives (per Bbl)	$ 47.14	$ 43.00	9.6%	$ 47.83	$ 37.42	27.8%

Oil, with realized derivatives (per Bbl)	$	50.11	$	43.00	16.5%	$	50.09	$	37.42	33.9%
Natural gas liquids, without realized derivatives (per Bbl)	$	22.55	$	15.15	48.8%	$	21.17	$	13.86	52.7%
Natural gas liquids, with realized derivatives (per Bbl)	$	22.55	$	15.15	48.8%	$	21.17	$	13.86	52.7%
Natural gas, without realized derivatives (per Mcf)	$	2.54	$	2.53	0.4%	$	2.71	$	2.04	32.8%
Natural gas, with realized derivatives (per Mcf)	$	2.76	$	2.53	9.1%	$	2.83	$	2.04	38.7%

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Oil Revenues

Successor Period

Our oil sales revenues for the three and nine months ended September 30, 2017 were $27.2 million and $85.5 million, respectively. Our oil sales revenues were comprised of $21.6 million and $67.8 million, respectively, from our Mississippian Lime assets and $5.6 million and $17.7 million, respectively, from our Anadarko Basin assets.

Predecessor Period

Our oil sales revenues for the three and nine months ended September 30, 2016 were $35.6 million and $104.8 million, respectively. Our oil sales revenue was comprised of $29.0 million and $85.2 million, respectively, from our Mississippian Lime assets and $6.6 million and $19.6 million, respectively, from our Anadarko Basin assets.

Natural Gas Revenues

Successor Period

Our natural gas sales revenues for the three and nine months ended September 30, 2017 were $14.0 million and $46.3 million, respectively. Our natural gas sales revenues were comprised of $12.1 million and $40.0 million, respectively, from our Mississippian Lime assets and $1.9 million and $6.3 million, respectively, from our Anadarko Basin assets.

Predecessor Period

Our natural gas sales revenues for the three and nine months ended September 30, 2016 were $17.7 million and $44.5 million, respectively. Our natural gas sales revenue was comprised of $15.5 million and $39.3 million, respectively, from our Mississippian Lime assets and $2.2 million and $5.2 million, respectively, from our Anadarko Basin assets.

NGL Revenues

Successor Period

Our NGLs sales revenues for the three and nine months ended September 30, 2017 were $10.7 million and $31.6 million, respectively. Our NGLs sales revenues were comprised of $8.5 million and $25.4 million, respectively, from our Mississippian Lime assets and $2.2 million and $6.2 million, respectively, from our Anadarko Basin assets.

Predecessor Period

Our NGLs sales revenues for the three and nine months ended September 30, 2016 were $8.9 million and $25.1 million, respectively. Our NGLs sales revenue was comprised of $7.3 million and $20.5 million, respectively, from our Mississippian Lime assets and $1.6 million and $4.6 million, respectively, from our Anadarko Basin assets.

Gains (losses) on Commodity Derivative Contracts Net

A summary of our open commodity derivative positions is included the financial statements in Part I. Financial Information Item 1. Financial Statements Notes to the Unaudited Condensed Consolidated Financial Statements Note 4. Risk Management and Derivative Instruments of this report. The following tables provide financial information associated with our oil and natural gas hedges for the period indicated (in thousands):

	For the Three Months Ended September 30, 2017	For the Nine Months Ended September 30, 2017
Cash settlements:		
Oil derivatives	$ 1,713	$ 4,041
Natural gas derivatives	1,196	2,108
Total cash settlements	**$ 2,909**	**$ 6,149**
Gains (losses) due to fair value changes:		
Oil derivatives	$ (5,618)	$ 925
Natural gas derivatives	(882)	1,693
Total gains (losses) on fair value changes	**$ (6,500)**	**$ 2,618**
Gains (losses) on commodity derivative contracts net	**$ (3,591)**	**$ 8,767**

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Successor Period

During the three and nine months ended September 30, 2017, we had unrealized gains (losses) of $(6.5) million and $2.6 million from our mark-to-market derivative positions, representing the changes in fair value from new positions and settlements that occurred during the period, as well as the relationship between contract prices and the associated forward curves. Cash receipts from the settlements of derivatives during the three and nine months ended September 30, 2017 were $2.9 million and $6.1 million, respectively.

Predecessor Period

We had no open or settled commodity derivative positions during the three and nine months ended September 30, 2016.

Oil, Natural Gas and NGL Production

	Successor For the Three Months Ended September 30, 2017	Predecessor For the Three Months Ended September 30, 2016	% Change	Successor For the Nine Months Ended September 30, 2017	Predecessor For the Nine Months Ended September 30, 2016	% Change
PRODUCTION DATA:						
Oil (Bbls/d)						
Mississippian Lime	4,940	7,266	(32.0)%	5,158	8,279	(37.7)%
Anadarko Basin	1,329	1,728	(23.1)%	1,389	1,947	(28.7)%
Natural gas liquids (Bbls/d)						
Mississippian Lime	4,145	5,209	(20.4)%	4,398	5,350	(17.8)%
Anadarko Basin	992	1,204	(17.6)%	1,066	1,250	(14.7)%
Natural gas (Mcf/d)						
Mississippian Lime	51,130	65,287	(21.7)%	53,474	68,612	(22.1)%
Anadarko Basin	8,581	10,624	(19.2)%	9,225	10,872	(15.1)%
Combined (Boe/d)						
Mississippian Lime	17,606	23,357	(24.6)%	18,469	25,065	(26.3)%
Anadarko Basin	3,752	4,702	(20.2)%	3,993	5,008	(20.3)%

Commodity production for the three and nine months ended September 30, 2017 is lower compared to the three and nine months ended September 30, 2016 due to natural decline and a lower level of drilling activity during the 2017 period.

Expenses

	Successor	Predecessor	Successor	Predecessor	Successor	Predecessor	Successor	Predecessor

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(in thousands)		(per Boe)		(in thousands)		(per Boe)	
EXPENSES:								
Lease operating and workover	$ 15,653	$ 17,650	$ 7.97	$ 6.84	$ 48,064	$ 49,520	$ 7.84	$ 6.01
Gathering and transportation	3,699	4,296	1.88	1.66	11,027	13,428	1.80	1.63
Severance and other taxes	2,352	1,788	1.20	0.69	6,168	4,776	1.01	0.58
Asset retirement accretion	274	452	0.14	0.17	833	1,316	0.14	0.16
Depreciation, depletion, and amortization	15,170	15,756	7.72	6.10	46,471	59,229	7.58	7.19
Impairment of oil and gas properties		33,887		13.13		224,584		27.26
General and administrative	7,255	3,308	3.69	1.27	23,102	19,093	3.77	2.32
Debt restructuring costs and advisory fees						7,589		0.92
Total expenses	**$ 44,403**	**$ 77,137**	**$ 22.60**	**$ 29.86**	**$ 135,665**	**$ 379,535**	**$ 22.14**	**$ 46.07**

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Lease Operating and Workover

Successor Period

Our lease operating and workover expenses for the three and nine months ended September 30, 2017 were $15.7 million and $48.1 million, respectively. Lease operating and workover expenses were $7.97 and $7.84 per Boe, respectively. As previously discussed in Part I. Financial Information Item 1. Financial Statements Notes to the Unaudited Condensed Consolidated Financial Statements Note 14. Commitments and Contingencies , lease operating and workover expenses were positively impacted during the nine months ended September 30, 2017 by a $1.9 million reimbursement received for an insurance claim.

Predecessor Period

Our lease operating and workover expenses for the three and nine months ended September 30, 2016 were $17.7 million and $49.5 million, respectively. Lease operating and workover expenses were $6.84 and $6.01 per Boe, respectively.

Gathering and Transportation

Successor Period

Our gathering and transportation expenses for the three and nine months ended September 30, 2017 were $3.7 million and $11.0 million, respectively. Gathering and transportation expenses were $1.88 and $1.80 per Boe, respectively.

Predecessor Period

Our gathering and transportation expenses for the three and nine months ended September 30, 2016 were $4.3 million and $13.4 million, respectively. Gathering and transportation expenses were $1.66 and $1.63 per Boe, respectively.

Severance and Other Taxes

	Successor Three Months Ended September 30, 2017 (in thousands)	Predecessor Three Months Ended September 30, 2016 (in thousands)	Successor Nine Months Ended September 30, 2017 (in thousands)	Predecessor Nine Months Ended September 30, 2016 (in thousands)
Total oil, natural gas, and natural gas liquids sales	**$ 51,816**	**$ 62,199**	**$ 163,398**	**$ 174,391**
Severance taxes	2,128	1,353	5,496	3,717
Ad valorem and other taxes	224	435	672	1,059
Severance and other taxes	**$ 2,352**	**$ 1,788**	**$ 6,168**	**$ 4,776**
Severance taxes as a percentage of sales	**4.1%**	**2.2%**	**3.4%**	**2.1%**
Severance and other taxes as a percentage of sales	**4.5%**	**2.9%**	**3.8%**	**2.7%**

Successor Period

Our severance and other tax expenses for the three and nine months ended September 30, 2017 were $2.4 million or 4.5% of sales and $6.2 million or 3.8% of sales, respectively. Severance tax for the three and nine months ended September 30, 2017 was $2.1 million or 4.1% of sales and $5.5 million or 3.4% of sales, respectively.

Prior to July 1, 2017, the State of Oklahoma had a crude oil and natural gas production tax incentive for wells that commenced production between July 1, 2011 and July 1, 2015, which allowed for a 1.0% production tax rate for the first 48 months of production. In May 2017, new legislation was signed into law in Oklahoma that increased the incentive tax rate from 1.0% to 4.0% on those wells. After the 48 month incentive period ends, the tax rate on such wells increases to 7.0%. The new 4.0% tax rate on these wells went into effect on July 1, 2017 and caused our average production tax rate to trend higher in the three months ended September 30, 2017. While the impact of increased production taxes is uncertain, based upon our current production, we estimate the elimination of these tax incentive wells will increase monthly production taxes by approximately $0.2 million.

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Predecessor Period

Our severance and other tax expenses for the three and nine months ended September 30, 2016 were $1.8 million or 2.9% of sales and $4.8 million or 2.7% of sales, respectively. Severance tax for the three and nine months ended September 30, 2016 was $1.4 million or 2.2% of sales and $3.7 million or 2.1% of sales, respectively.

Depreciation, Depletion and Amortization (DD&A)

Successor Period

Our DD&A expenses for the three and nine months ended September 30, 2017 were $15.2 million at a cost of $7.72 per Boe and $46.5 million at a cost of $7.58 per Boe, respectively.

Predecessor Period

Our DD&A expenses for the three and nine months ended September 30, 2016 were $15.8 million at a cost of $6.10 per Boe and $59.2 million at a cost of $7.19 per Boe, respectively.

Impairment of Oil and Gas Properties

Successor Period

We did not incur any impairments of oil and gas properties during the three or nine months ended September 30, 2017.

Predecessor Period

Our impairment of oil and gas properties for the three and nine months ended September 30, 2016 was $33.9 million and $224.6 million, respectively. The impairment expense recognized in the Predecessor Period was primarily due to a decrease in the PV-10 value of our proven oil and natural gas reserves as a result of continued low commodity prices, which are a significant input into the calculation of the discounted future cash flows associated with our proved oil and gas reserves.

General and Administrative (G&A)

Successor Period

Our G&A expense for the three and nine months ended September 30, 2017 was $7.3 million at a cost of $3.69 per Boe and $23.1 million at a cost of $3.77 per Boe, respectively. G&A for the three and nine months ended September 30, 2017 was impacted by non-cash stock based compensation expense for awards issued pursuant to the 2016 LTIP of $2.8 million and $7.1 million, respectively, as well as trailing costs incurred related to the Chapter 11 Cases of $0.1 million and $2.7 million, respectively.

Predecessor Period

Our G&A expense for the three and nine months ended September 30, 2016 was $3.3 million at a cost of $1.27 per Boe and $19.1 million at a cost of $2.32 per Boe, respectively. G&A for the nine months ended September 30, 2016 included the acceleration of rent and related expenses associated with the Houston office lease abandonment totaling $2.5 million.

Debt Restructuring Costs and Advisory Fees

Successor Period

We did not incur any debt restructuring costs or advisory fees during the three or nine months ended September 30, 2017. Trailing costs associated with the Chapter 11 Cases incurred subsequent to the Emergence Date are included in G&A expense, as discussed above.

Predecessor Period

For the nine months ended September 30, 2016 we incurred $7.6 million of advisory fees to assist with analyzing various strategic alternatives to address our liquidity and capital structure. Costs associated with the Chapter 11 Cases incurred subsequent to April 30, 2016 were included in reorganization items, net, as discussed below.

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Other Expense

	Successor For the Three Months Ended September 30, 2017 (in thousands)	Predecessor For the Three Months Ended September 30, 2016 (in thousands)	Successor For the Nine Months Ended September 30, 2017 (in thousands)	Predecessor For the Nine Months Ended September 30, 2016 (in thousands)
OTHER EXPENSE				
Interest income	$	$	$	$ 81
Interest expense	(1,949)	(2,668)	(5,630)	(73,965)
Amortization of deferred financing costs	(108)		(277)	
Amortization of deferred gain				8,246
Capitalized interest	408		2,053	
Interest expense net of amounts capitalized	(1,649)	(2,668)	(3,854)	(65,719)
Reorganization items, net		(22,772)		57,764
Total other expense	**$ (1,649)**	**$ (25,440)**	**$ (3,854)**	**$ (7,874)**

Interest Expense

Successor Period

Interest expense for the three and nine months ended September 30, 2017 was $1.9 million and $5.6 million, respectively. Interest expense related to our Exit Facility bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. For the three months ended September 30, 2017, the weighted average interest rate was 5.7%. We also capitalized $0.4 million and $2.1 million, respectively, of interest expense to our unproved oil and gas properties during the three and nine months ended September 30, 2017.

Predecessor Period

Our interest expense for the three and nine months ended September 30, 2016 was $2.7 million and $74.0 million, respectively. During the three and nine months ended September 30, 2016, interest expense ceased for all debt except amounts outstanding under the credit facility beginning at the petition date of April 30, 2016. During the nine months ended September 30, 2016, interest expense was offset by $8.2 million related to the amortization of the deferred gain on extinguished debt. No interest expense was capitalized for the three and nine months ended September 30, 2016, due to the transfer of all balances related to unproved properties to the full cost pool at December 31, 2015.

Provision for Income Taxes

Successor Period

We recorded no income tax expense or benefit due to the change in our valuation allowance recorded against our net deferred tax assets. Our valuation allowance decreased by $13.0 million from December 31, 2016 bringing our total valuation allowance to $147.8 million at September 30, 2017.

Predecessor Period

We recorded no income tax expense or benefit. During the nine months ended September 30, 2016, we recorded $70.9 million in additional valuation allowance, bringing the total valuation allowance to $766.0 million at September 30, 2016.

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Reorganization Items, Net

Successor Period

We did not incur any reorganization items during the three or nine months ended September 30, 2017.

Predecessor Period

We recognized a net loss of $(22.8) million and a net gain of $57.8 million in reorganization items, net during the three and nine months ended September 30, 2016, respectively. Reorganization items, net represent the direct and incremental costs of being in bankruptcy, such as professional fees, pre-petition liability claim adjustments and losses related to terminated contracts that are probable and can be estimated.

Liquidity and Capital Resources

Overview

The following table presents a summary of our key financial indicators at the dates presented (in thousands):

	September 30, 2017	December 31, 2016
Cash and cash equivalents	$ 76,548	$ 76,838
Net working capital	58,397	67,637
Total long-term debt	128,059	128,059
Total stockholders equity	605,597	561,814
Available borrowing capacity	40,000	

Our decisions regarding capital structure, hedging and drilling are based upon many factors, including anticipated future commodity pricing, expected economic conditions and recoverable reserves.

We anticipate our operating cash flows and cash on hand will be our primary sources of liquidity although we may seek to supplement our liquidity through divestitures, additional borrowings or debt or equity securities offerings as circumstances and market conditions dictate. We believe the combination of these sources of liquidity will be adequate to fund anticipated capital expenditures, service our existing debt and remain compliant with all other contractual commitments.

Our cash flows from operations are impacted by various factors, the most significant of which is the market pricing for oil, NGLs and natural gas. The pricing for these commodities is volatile, and the factors that impact such market pricing are global and therefore outside of our control. As a result, it is not possible for us to precisely predict our future cash flows from operating revenues due to these market forces.

We enter into hedging activities with respect to a portion of our production to manage our exposure to oil, NGLs and natural gas price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts.

Consistent with our comprehensive growth strategy of focusing on a portfolio of core assets capable of supporting a long-term, sustainable drilling program, we are actively considering more substantial divestitures and other asset monetization transactions with respect to assets that we do not believe meet our strategic objectives. These transactions may involve significant asset positions, entire business units or corporate level transactions. Depending upon the success, timing and structure of any such transactions, the amount of proceeds we receive from portfolio management activity could materially increase during the remainder of 2017. In conjunction with our consideration of more substantial divestitures, we are also considering substantial acquisitions or other business combinations that further our comprehensive growth strategy.

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Significant Sources of Capital

Exit Facility

At September 30, 2017, in addition to cash on hand of $76.5 million, we maintained the Exit Facility. The Exit Facility has a current borrowing base of $170.0 million. At September 30, 2017, we had $128.1 million drawn on the Exit Facility and outstanding letters of credit obligations totaling $1.9 million. As of September 30, 2017, we had $40.0 million of availability on the Exit Facility.

The Exit Facility bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. For the three months ended September 30, 2017, the weighted average interest rate was 5.7%.

In addition to interest expense, the Exit Facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of 0.50% per annum based on the average daily amount by which the borrowing base exceeds outstanding borrowings during each quarter.

On May 24, 2017, we entered into the First Amendment to the Exit Facility. The First Amendment, among other items, (i) moved the first scheduled borrowing base redetermination from April 2018 to October 2017; (ii) removed the requirement to maintain a cash collateral account with the administrative agent in the amount of $40.0 million; (iii) removed the requirement to maintain at least 20% liquidity of the then effective borrowing base; (iv) amended the required mortgage threshold from 95% to 90%; (v) amended the threshold amount for which the borrower is required to provide advance notice to the administrative agent of a sale or disposition of oil and gas properties which occurs during the period between two successive redeterminations of the borrowing base; (vi) amended the required ratio of total net indebtedness to EBITDA from 2.25:1.00 to 4.00:1.00; (vii) amended the required EBITDA to interest coverage ratio from not less than 3.00:1.00 to not less than 2.50:1.00; and (viii) removed certain limitations on capital expenditures.

As of September 30, 2017, we were in compliance with our debt covenants.

On October 27, 2017, the Company s borrowing base was redetermined at the existing amount of $170.0 million. Our Anadarko Basin assets in Texas and Oklahoma were excluded from the redetermination of the borrowing base.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our condensed consolidated cash flows from operating, investing and financing activities for the periods presented. For information regarding the individual components of our cash flow amounts, please refer to the unaudited condensed consolidated statements of cash flows included under Part I. Financial Information Item 1. Financial Statements of this Quarterly Report.

Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of these commodities. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see Part I. Financial Information Item 3. Quantitative and Qualitative Disclosures about Market Risk.

The following information highlights the significant period-to-period variances in our cash flow amounts (in thousands):

	Successor For the Nine Months Ended September 30, 2017		Predecessor For the Nine Months Ended September 30, 2016	
Net cash provided by operating activities	$	89,317	$	78,244
Net cash used in investing activities		(88,606)		(129,072)
Net cash (used in) provided by financing activities		(1,001)		249,331
Net change in cash	**$**	**(290)**	**$**	**198,503**

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Cash flows provided by operating activities

Net cash provided by operating activities was $89.3 million and $78.2 million for the nine months ended September 30, 2017 and 2016, respectively.

Cash flows used in investing activities

We had net cash used in investing activities of $88.6 million and $129.1 million for the nine months ended September 30, 2017 and 2016, respectively. Net cash used in investing activities for the Successor Period and Predecessor Period primarily represents cash invested in oil and gas property and equipment.

Cash flows (used in) provided by financing activities

We had net cash used in financing activities for the nine months ended September 30, 2017, of $1.0 million and net cash provided by financing activities for the nine months ended September 30, 2016, of $249.3 million. Net cash used in financing activity for the Successor Period relates to deferred financing costs and the acquisition of treasury stock. Net cash provided by financing activities for the Predecessor Period primarily represents borrowings from the revolving credit facility of $249.4 million.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our Annual Report on Form 10-K for the year ended December 31, 2016. There have been no material changes to those policies. When used in the preparation of our unaudited condensed consolidated financial statements, estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our unaudited condensed consolidated financial position, results of operations and cash flows.

Other Items

Obligations and Commitments

We have various contractual obligations for operating leases, including drilling contracts, as well as lease commitments and commitments under our Exit Facility. Information regarding these various obligations and commitments are included in our Annual Report on Form 10-K for the year ended December 31, 2016. There have been no significant changes in these obligations and commitments.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity and capital resource positions or for any other purpose. However, as is customary in the oil and gas industry, we may, from time to time, have various contractual work commitments and/or letters of credit as described in our notes to the unaudited condensed consolidated financial statements.

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Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASU 2014-09). ASU 2014-09 provides guidance concerning the recognition and measurement of revenue from contracts with customers. The objective of ASU 2014-09 is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. We have completed our review of contracts for each revenue stream identified within our business and are currently finalizing our conclusion on any changes in revenue recognition upon adoption of the revised guidance. Based on assessments to date, we believe ASU 2014-09 will impact the presentation of future revenues and expenses by including certain transportation and gathering costs, along with various other fees such as compression and marketing fees net within revenues. The inclusion of these costs within revenues will not impact our revenue recognition, financial position, net income or cash flows. In addition, several industry interpretations are currently open for public comment. We cannot quantitatively assess the impact of ASU 2014-09 on our financial statements until final consensus is reached on these various industry matters. Once all pending industry interpretations are addressed, we will finalize our assessment of ASU 2014-09. We are in the process of evaluating the information technology and internal control changes that will be required for adoption based on our contract review process, but we do not currently anticipate material impacts to either information technology or internal controls. However, this assessment is pending conclusion of various industry interpretations. We intend to apply the modified retrospective approach upon adoption of this standard on the effective date of January 1, 2018.

In February 2016, the FASB issued Accounting Standards Update 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. All leases create an asset and a liability for the lessee and therefore recognition of those lease assets and lease liabilities is required by ASU 2016-02. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are in the initial evaluation and planning stages for ASU 2016-02 and do not expect to move beyond this stage until completion of its evaluation of ASU 2014-09, which is expected to occur in the latter half of 2017.

In July 2017, the FASB issued Accounting Standards Update 2017-11, *Earnings Per Share (Topic 260), Distinguishing Liabilities from Equity (Topic 480), and Derivatives and Hedging (Topic 815)* (ASU 2017-11). ASU 2017-11 changes the classification analysis of certain equity-linked financial instruments (or embedded features) with down round features. The amendments require entities that present earnings per share (EPS) in accordance with Topic 260 to recognize the effect of the down round feature when triggered with the effect treated as a dividend and as a reduction of income available to common shareholders in basic EPS. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We do not believe the adoption of ASU 2017-11 will have a material impact on its financial position, results of operations or cash flows.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses or gains, but rather indicators of reasonably possible losses or gains. 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 purposes other than speculative trading. These derivative instruments are discussed in Part I. Financial Information Item 1. Financial Statements Notes to the Unaudited Condensed Consolidated Financial Statements Note 4. Risk Management and Derivative Instruments.

Commodity Price Exposure

We are exposed to market risk as the prices of oil, NGLs and natural gas fluctuate due to changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged and in the long-term, expect to hedge, a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil and natural gas prices. As of September 30, 2017, we utilized fixed price swaps, collars and three way collars to reduce the volatility of oil and natural gas prices on a portion of our future expected oil and natural gas production.

For derivative instruments recorded at fair value, the credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet.

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At September 30, 2017, a 10% change in the forward curves associated with our commodity derivative instruments would have changed our net asset positions by the following amounts:

	10% Increase	10% Decrease
	(in thousands)	
Gain (loss):		
Gas derivatives	$ (2,408)	$ 2,273
Oil derivatives	$ (5,482)	$ 5,473

Interest Rate Risk

At September 30, 2017, we had indebtedness outstanding under our Exit Facility of $128.1 million, which bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. Assuming the Exit Facility is fully drawn, a one percent increase in interest rates for the three months ended September 30, 2017 would have resulted in a $0.4 million increase in interest cost, before capitalization.

At September 30, 2017, we did not have any interest rate derivatives in place and have not historically utilized interest rate derivatives. In the future, we may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing or future debt issues. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

During the period covered by this report, our management carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our President and Chief Executive Officer and our Vice President and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosures. Based on that evaluation, our President and Chief Executive Officer and our Vice President and Chief Accounting Officer concluded that as of September 30, 2017, these disclosure controls and procedures were effective and ensured that the information required to be disclosed in our reports filed with the SEC is recorded, processed, summarized and reported on a timely basis.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2017, 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

From time to time, we are party to various legal proceedings arising in the ordinary course of business. Although we cannot predict the outcomes of any such legal proceedings, our management believes that the resolution of currently pending legal actions will not have a material adverse effect on our business, results of operations and financial condition. See Part I. Financial Information Item 1. Financial Statements Notes to the Unaudited Condensed Consolidated Financial Statements Note 14. Commitments and Contingencies , which is incorporated in this item by reference.

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed in this Quarterly Report and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

In addition to the other information set forth in this report, you should carefully consider the factors discussed below and described in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on March 30, 2017.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater produced in conjunction with our hydrocarbons, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater produced in conjunction with the oil and natural gas produced from our drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, the applicable legal requirements may be subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to dispose of saltwater by plugging back the depths of disposal wells, reducing the volume of oil and natural gas wastewater disposed in such wells, restricting disposal well locations, or requiring us to shut down disposal wells, could require the Company to cease operations at a substantial number of its oil and natural gas wells, which would have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition and results of operations.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibits included in this Quarterly Report are listed in the Exhibit Index and incorporated herein by reference.

EXHIBIT INDEX

Exhibit Number	Exhibit Description
2.1	First Amended Joint Chapter 11 Plan Of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate, dated September 28, 2016 (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K filed on October 4, 2016, and incorporated herein by reference).
3.1	Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company s Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Midstates Petroleum Company, Inc. (filed as Exhibit 3.2 to the Company s Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
4.1	Warrant Agreement, dated as of October 21, 2016 between Midstates Petroleum Company, Inc. and American Stock Transfer & Trust Company, LLC (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
4.2	Warrant Agreement, dated as of October 21, 2016, between Midstates Petroleum Company, Inc. and American Stock Transfer & Trust Company, LLC (filed as Exhibit 4.2 to the Company s Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
10.1	First Amendment to Senior Secured Credit Agreement, dated May 24, 2017, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, as borrower, SunTrust Bank, as administrative agent, and certain lenders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 26, 2017, and incorporated herein by reference).
10.2	Separation Agreement and General Release of Claims, dated as of June 7, 2017, by and between Midstates Petroleum Company, Inc. and Nelson M. Haight (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on June 7, 2017, and incorporated herein by reference).
10.3	Amendment No. 1 to Executive Employment Agreement, dated as of August 22, 2017, by and between Midstates Petroleum Company, Inc. and Frederic F. Brace (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on August 25, 2017, and incorporated herein by reference).
10.4	Executive Employment Agreement, effective as of November 1, 2017, by and between Midstates Petroleum Company, Inc. and David J. Sambrooks (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on October 26, 2017, and incorporated herein by reference).
10.5	Form of Restricted Stock Unit Award Agreement, effective as of November 1, 2017, by and between Midstates Petroleum Company, Inc. and David J. Sambrooks (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K filed on October 26, 2017, and incorporated herein by reference).
10.6	Form of Performance Stock Unit Award Agreement, effective as of November 1, 2017, by and between Midstates Petroleum Company, Inc. and David J. Sambrooks (filed as Exhibit 10.3 to the Company s Current Report on Form 8-K filed on October 26, 2017, and incorporated herein by reference).
10.7	Borrowing Base Redetermination Agreement, dated as of October 27, 2017, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, the lenders party thereto and SunTrust Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on November 1, 2017, and incorporated herein by reference).
31.1*	Sarbanes-Oxley Section 302 certification of Principal Executive Officer

31.2*	Sarbanes-Oxley Section 302 certification of Principal Financial Officer
32.1**	Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer

101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith
** Furnished herewith

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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.

	MIDSTATES PETROLEUM COMPANY, INC.
Dated: November 14, 2017	/s/ David J. Sambrooks David J. Sambrooks President and Chief Executive Officer (Principal Executive Officer)
Dated: November 14, 2017	/s/ Richard W. McCullough Richard W. McCullough Vice President and Chief Accounting Officer (Principal Financial Officer and Principal Accounting Officer)