UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended June 30, 2018

OR

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

For the transition period from to .

Commission File Number: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company, 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 ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

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. ☐

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

The number of shares outstanding of our stock at August 2, 2018 is shown below:

Class	Number of shares outstanding
Common stock, $0.01 par value	25,256,957

DOCUMENTS INCORPORATED BY REFERENCE
None.

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MIDSTATES PETROLEUM COMPANY, INC.
QUARTERLY REPORT ON
FORM 10-Q
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2018

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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)

	June 30, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,256	$ 68,498
Accounts receivable:		
Oil and gas sales	30,278	32,455
Joint interest billing	4,598	3,297
Other	298	166
Commodity derivative contracts	—	762

Other current assets	2,474	1,510
Total current assets	43,904	106,688
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting		
Proved properties	778,741	765,308
Unproved properties not being amortized	4,383	7,065
Other property and equipment	6,243	6,508
Less accumulated depreciation, depletion, amortization and impairment	(235,948)	(204,419)
Net property and equipment	553,419	574,462
OTHER NONCURRENT ASSETS	5,263	6,978
TOTAL	**$ 602,586**	**$ 688,128**
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 19,216	$ 11,547
Accrued liabilities	40,327	42,842
Commodity derivative contracts	11,549	3,433
Total current liabilities	71,092	57,822
LONG-TERM LIABILITIES:		
Asset retirement obligations	7,573	15,506
Commodity derivative contracts	3,293	562
Long-term debt	28,059	128,059
Other long-term liabilities	578	592
Total long-term liabilities	39,503	144,719
COMMITMENTS AND CONTINGENCIES (Note 14)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized; no shares issued or outstanding at June 30, 2018 and December 31, 2017	—	—
Warrants, 6,625,554 warrants outstanding at June 30, 2018 and December 31, 2017	37,329	37,329
Common stock, $0.01 par value, 250,000,000 shares authorized; 25,386,104 shares issued and 25,256,957 shares outstanding at June 30, 2018; 25,272,969 shares issued and 25,173,346 shares outstanding at December 31, 2017	254	253
Treasury stock	(2,081)	(1,603)
Additional paid-in-capital	529,175	524,755
Retained deficit	(72,686)	(75,147)
Total stockholders' equity	491,991	485,587
TOTAL	**$ 602,586**	**$ 688,128**

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

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MIDSTATES PETROLEUM COMPANY, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands, except per share amounts)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
REVENUES:				
Oil sales	$ 34,202	$ 27,271	$ 66,616	$ 58,307
Natural gas liquid sales	11,893	9,730	22,931	20,924
Natural gas sales	6,782	15,253	15,119	32,351
Other revenue	795	932	1,850	1,754
Total revenues from contracts with customers	53,672	53,186	106,516	113,336
Gains (losses) on commodity derivative contracts—net	(11,348)	7,493	(15,287)	12,358
Total revenues	42,324	60,679	91,229	125,694
EXPENSES:				
Lease operating and workover	16,952	16,559	31,760	32,411
Gathering and transportation (Note 3)	67	3,641	124	7,328
Severance and other taxes	2,776	1,695	5,638	3,816
Asset retirement accretion	250	283	547	559
Depreciation, depletion, and amortization	16,484	15,959	31,697	31,301
General and administrative	5,190	7,572	15,047	15,847
Advisory fees	850	—	850	—
Total expenses	42,569	45,709	85,663	91,262
OPERATING INCOME (LOSS)				

OTHER EXPENSE:	(245)	14,970	5,566	34,432
Interest income	5	—	24	—
Interest expense—net of amounts capitalized	(1,302)	(1,228)	(3,129)	(2,205)
Total other expense	(1,297)	(1,228)	(3,105)	(2,205)
INCOME (LOSS) BEFORE TAXES	**(1,542)**	**13,742**	**2,461**	**32,227**
Income tax expense	—	—	—	—
NET INCOME (LOSS)	**$ (1,542)**	**$ 13,742**	**$ 2,461**	**$ 32,227**
Participating securities—non-vested restricted stock	—	(360)	(68)	(897)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$ (1,542)**	**$ 13,382**	**$ 2,393**	**$ 31,330**
Basic and diluted net income (loss) per share attributable to common shareholders	$ (0.06)	$ 0.53	$ 0.09	$ 1.25
Basic and diluted weighted average number of common shares outstanding (Note 12)	25,332	25,093	25,316	25,053

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

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MIDSTATES PETROLEUM COMPANY, INC.
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Unaudited)
(In thousands)

	Series A Preferred Stock	Common Stock	Warrants	Treasury Stock	Additional Paid-in-Capital	Retained Deficit	Total Stockholders' Equity
Balance as of December 31, 2017	**$ —**	**$ 253**	**$ 37,329**	**$ (1,603)**	**$ 524,755**	**$ (75,147)**	**$ 485,587**
Share-based compensation	—	1	—	—	4,420	—	4,421
Acquisition of treasury stock	—	—	—	(478)	—	—	(478)
Net income	—	—	—	—	—	2,461	2,461
Balance as of June 30, 2018	**$ —**	**$ 254**	**$ 37,329**	**$ (2,081)**	**$ 529,175**	**$ (72,686)**	**$ 491,991**

	Series A Preferred Stock	Common Stock	Warrants	Treasury Stock	Additional Paid-in-Capital	Retained Earnings	Total Stockholders' Equity
Balance as of December 31, 2016	**$ —**	**$ 250**	**$ 37,329**	**$ —**	**$ 514,305**	**$ 9,930**	**$ 561,814**
Share-based compensation	—	1	—	—	5,251	—	5,252
Acquisition of treasury stock	—	—	—	(622)	—	—	(622)
Net income	—	—	—	—	—	32,227	32,227
Balance as of June 30, 2017	**$ —**	**$ 251**	**$ 37,329**	**$ (622)**	**$ 519,556**	**$ 42,157**	**$ 598,671**

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

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MIDSTATES PETROLEUM COMPANY, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	For the Six Months Ended June 30,	
	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 2,461	$ 32,227
Adjustments to reconcile net income to net cash provided by operating activities:		
(Gains) losses on commodity derivative contracts—net	15,287	(12,358)
Net cash received (paid) for commodity derivative contracts not designated as hedging instruments	(3,677)	3,240
Asset retirement accretion	547	559
Depreciation, depletion, and amortization	31,697	31,301
Share-based compensation, net of amounts capitalized to oil and gas properties	3,425	4,267
Amortization of deferred financing costs	216	169
Change in operating assets and liabilities:		
Accounts receivable—oil and gas sales	1,437	5,519
Accounts receivable—JIB and other	(1,713)	1,310

Other current and noncurrent assets		(754)		642
Accounts payable		2,301		809
Accrued liabilities		(1,921)		(4,466)
Other		(14)		(42)
Net cash provided by operating activities	**$**	**49,292**	**$**	**63,177**
CASH FLOWS FROM INVESTING ACTIVITIES:				
Investment in property and equipment	$	(65,843)	$	(54,369)
Proceeds from the sale of oil and gas properties		54,432		—
Proceeds from the sale of oil and gas equipment		355		1,350
Net cash used in investing activities	**$**	**(11,056)**	**$**	**(53,019)**
CASH FLOWS FROM FINANCING ACTIVITIES:				
Repayment of revolving credit facility	$	(100,000)	$	—
Deferred financing costs		—		(375)
Repurchase of restricted stock for tax withholdings		(478)		(622)
Net cash used in financing activities	**$**	**(100,478)**	**$**	**(997)**
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**$**	**(62,242)**	**$**	**9,161**
Cash and cash equivalents, beginning of period	**$**	**68,498**	**$**	**76,838**
Cash and cash equivalents, end of period	**$**	**6,256**	**$**	**85,999**
SUPPLEMENTAL INFORMATION:				
Non-cash transactions — investments in property and equipment accrued — not paid	$	23,219	$	17,055
Cash paid for interest, net of capitalized interest of $0.2 million and $1.6 million, respectively	$	3,010	$	2,107

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

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MIDSTATES PETROLEUM COMPANY, INC.
Notes to Unaudited Interim 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. 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," and similar terms refer to Midstates Petroleum Company, Inc. and its subsidiary.

The Company currently conducts oil and gas operations and owns and operates oil and natural gas properties in Oklahoma. The Company operates nearly all 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.

2. Summary of Significant Accounting Policies

Basis of Presentation

These unaudited interim condensed consolidated financial statements 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, these financial statements 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, 2017 included in the Company's Annual Report on Form 10-K as filed with the SEC on March 14, 2018.

All intercompany transactions have been eliminated in consolidation. In the opinion of the Company's management, the accompanying unaudited interim 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 interim condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the unaudited interim 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.

As a result of the adoption of Accounting Standards Update 2014-09, *"Revenue from Contracts with Customers (Topic 606)*" ("ASU 2014-09"), certain balances included in the unaudited interim condensed consolidated statements of operations for prior periods have been reclassified to conform to the 2018 presentation. These reclassifications had no impact on net income, cash flows or stockholders' equity for any period presented.

Recent Accounting Pronouncements Adopted During the Period

In March 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2018-05, "Income Taxes (Topic 740), Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118" ("ASU 2018-05"). ASU 2018-

05 amends certain SEC paragraphs pursuant to the issuance of the December 2017 SEC Staff Accounting Bulletin No. 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* ("SAB 118"), which provides guidance on accounting for the tax effects of the Tax Cuts and Jobs Act ("the Tax Act"). SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act's enactment date for companies to complete its accounting under FASB Accounting Standards Codification ("ASC") 740. In accordance with SAB 118, to the extent a company has not completed its analysis of the Tax Act but can provide a reasonable estimate, it must record a provisional estimate in its financial statements. The Company has accounted for certain tax effects of the Tax Act under the guidance of SAB 118, on a provisional basis. The Company's accounting for certain income tax effects is incomplete due to forthcoming guidance and the ongoing analysis of final year-end data and tax positions. The Company expects to complete its analysis within the measurement period in accordance with SAB 118.

In May 2014, the FASB issued 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 adopted ASU 2014-09 using the modified retrospective approach. The adoption of this guidance did not have a material impact on the Company's financial statements. See Note 3 below for further details.

Recent Accounting Pronouncements Issued But Not Yet Adopted

In June 2018, the FASB issued Accounting Standards Update 2018-07, "*Compensation - Stock Compensation (Topic 718) — Improvements to Nonemployee Share-Based Payment Accounting*" ("ASU 2018-07"). ASU 2018-07 expands the scope of Topic 718 to include share-based payments issued to nonemployees for goods and services. Consequently, the accounting for share-based payments to nonemployees and employees with be substantially aligned. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company does not believe the adoption of ASU 2018-07 will have a material impact on its financial position, results of operations or cash flows.

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.

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. When measuring lease assets and liabilities, payments to be made in optional extension periods should be included if the lessee is reasonably certain to exercise the option. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement.

For finance leases, the Company will recognize a ROU asset and liability, initially measured at the present value of the lease payments. Interest expense will be recognized on the lease liability separately from the amortization of the ROU asset. The Company will recognize payments of principal on the lease liability within financing activities in the consolidated statement of cash flows and payments of interest within operating activities in the consolidated statement of cash flows. For operating leases, the Company will recognize a ROU asset and liability, initially measured at the present value of the lease payments. The Company will recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis and all cash payments will be recognized in operating activities within the consolidated statement of cash flows.

In January 2018, the FASB issued Accounting Standards Update 2018-01, "*Leases (Topic 842)-Land Easement Practical Expedient for Transition to Topic 842*" ("ASU 2018-01"). ASU 2018-01 permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expired prior to a company's adoption of ASU 2016-02 and that were not accounted for as leases under previous lease guidance. 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 currently analyzing contracts to determine if they meet the definition of a lease under ASU 2016-02. The Company cannot reasonably quantify the impact of adoption at this time and expects to complete the assessment of ASU 2016-02 during the fourth quarter of 2018.

3. Impact of ASC 606 Adoption

On January 1, 2018, the Company adopted Accounting Standards Codification 606, *Revenue from Contracts with Customers* ("ASC 606") using the modified retrospective method of transition. ASC 606 supersedes previous revenue recognition requirements in Accounting Standards Codification 605, *Revenue Recognition* ("ASC 605") and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

The impact of adoption on the Company's results is as follows for the periods presented (in thousands):

	Three Months Ended June 30, 2018		
	Under ASC 606	**Under ASC 605**	**Decrease**
Oil sales	$ 34,202	$ 34,218	$ (16)
Natural gas liquid sales	11,893	11,911	(18)
Natural gas sales	6,782	10,187	(3,405)
Gathering and transportation	67	3,429	(3,362)
Lease operating and workover expense	16,952	17,029	(77)
Net loss	$ (1,542)	$ (1,542)	$ —
Retained deficit	$ (72,686)	$ (72,686)	$ —

	Six Months Ended June 30, 2018		
	Under ASC 606	**Under ASC 605**	**Decrease**
Oil sales	$ 66,616	$ 66,642	$ (26)
Natural gas liquid sales	22,931	22,976	(45)
Natural gas sales	15,119	21,587	(6,468)
Gathering and transportation	124	6,499	(6,375)
Lease operating and workover expense	31,760	31,924	(164)
Net income	$ 2,461	$ 2,461	$ —
Retained deficit	$ (72,686)	$ (72,686)	$ —

The primary impact to the Company's revenues as a result of the adoption of ASC 606 is the netting of certain deductions and costs against revenue instead of its historical practice of presenting such expenses gross in gathering and transportation. These changes are due to analysis of the control model in ASC 606. Further discussion of the Company's revenue recognition under ASC 606 is included below.

Revenue Recognition

Oil, NGLs and natural gas revenues are recognized at the point in time that control of the product is transferred to the customer and collectability is reasonably assured. Other revenue consists of iodine royalty income, which are point in time sales, and salt water disposal income, which is recognized over time. A more detailed summary of the underlying contracts that give rise to revenue and the method of recognition is included below.

Natural Gas and NGLs Sales

Under the Company's gas processing contracts, it delivers natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity processes the natural gas, sells the resulting NGLs and residue gas to third-parties and pays the Company for the NGLs and residue gas. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts that the Company concluded that it was the principal, the ultimate third party is the customer, and it recognizes revenue on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense. Alternatively, for those contracts that the Company has concluded that it is the agent, the purchaser is its customer, and it recognizes revenue based on the net amount of the proceeds received from the purchaser.

Oil Sales

Under the Company's oil sales contracts, it delivers all or a specified percentage of the crude oil production from specified leases to the purchaser at the wellhead. The Company sells oil production at the wellhead and collects an agreed-upon index price, net of applicable transport costs. The Company recognizes revenue when control transfers to the purchaser at the wellhead at the net price received.

Other Revenue

Other revenue consists of fees charged to outside working interest owners for salt water disposal as well as royalties received from a third-party for iodine extracted from the Company's salt water. Salt water disposal revenue is recognized over time because the customer simultaneously receives and consumes the benefit of the salt water disposal service as the service is provided. For salt water disposal income the Company utilized the practical expedient in ASC 606-10-55-18 that states that if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date, the entity may recognize revenue in the amount to which the entity has a right to invoice. Iodine royalty revenue is recognized point-in-time when control transfers to the customer.

Imbalances

The Company recognizes revenue for all oil, NGLs and natural gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil and gas reserves. The Company had no significant imbalances at June 30, 2018 or December 31, 2017.

Significant Judgments

Principal versus agent

The Company engages in various types of transactions in which midstream entities process its wet gas and, in some scenarios, subsequently market resulting NGLs and residue gas to third-party customers on its behalf, such as its percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether the Company is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. The Company analyzed control under ASC 606 and determined for those contracts where control passes at the wellhead, the Company acts as agent and revenue should be recognized net of amounts paid after such control passed for costs such as gathering, compression, processing and transportation, among others. The determination of control and the presentation of revenues was completed for ASC 606 purposes only. Amounts paid by the Company for royalties are calculated under a different methodology and may differ from the amount of revenues recognized under ASC 606.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 that exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, it has utilized the practical expedient in ASC 606-10-50-14A that states it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

For salt water disposal income, the Company has utilized the practical expedient in ASC 606-10-50-14 that states that if it recognizes revenue from the satisfaction of the performance obligation in accordance with the right to invoice practical expedient then it is exempted from disclosure of the transaction price allocated to remaining performance obligations.

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Prior-period performance obligations

The Company records revenue in the month production is delivered and control passes to the customer. However settlement statements and payment may not be received for 30 to 90 days after the date production occurs, and as a result, the Company is required to estimate the amount of production that was delivered and the price that will be received for the sale of the product. The Company utilizes its knowledge of the properties, its historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices and other pertinent factors as the basis for these estimates. The Company records the variances between its estimates and the actual amounts received in the month payment is received and such variances have historically not been significant. For the three and six months ended June 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

4. 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 interim condensed consolidated balance sheets are recorded at estimated fair value. At June 30, 2018, 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 interim condensed consolidated statements of operations.

	Fair Value Measurements at June 30, 2018			
	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	$ —	$ —	$ —	$ —
Commodity derivative gas swaps	$ —	$ 79	$ —	$ 79
Commodity derivative oil collars	$ —	$ 3,058	$ —	$ 3,058
Commodity derivative gas collars	$ —	$ 698	$ —	$ 698
Total assets	**$ —**	**$ 3,835**	**$ —**	**$ 3,835**
Derivative Liabilities:				
Commodity derivative oil swaps	$ —	$ (6,371)	$ —	$ (6,371)
Commodity derivative gas swaps	$ —	$ (476)	$ —	$ (476)
Commodity derivative oil collars	$ —	$ (11,408)	$ —	$ (11,408)
Commodity derivative gas collars	$ —	$ (422)	$ —	$ (422)
Total liabilities	**$ —**	**$ (18,677)**	**$ —**	**$ (18,677)**

	Fair Value Measurements at December 31, 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	$ —	$ —	$ —	$ —
Commodity derivative gas swaps	$ —	$ 821	$ —	$ 821
Commodity derivative oil collars	$ —	$ 952	$ —	$ 952
Commodity derivative gas collars	$ —	$ 2,611	$ —	$ 2,611
Total assets	**$ —**	**$ 4,384**	**$ —**	**$ 4,384**
Derivative Liabilities:				
Commodity derivative oil swaps	$ —	$ (3,679)	$ —	$ (3,679)
Commodity derivative gas swaps	$ —	$ —	$ —	$ —
Commodity derivative oil collars	$ —	$ (2,605)	$ —	$ (2,605)
Commodity derivative gas collars	$ —	$ (1,333)	$ —	$ (1,333)
Total liabilities	**$ —**	**$ (7,617)**	**$ —**	**$ (7,617)**

5. 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 and natural gas production. The Company utilizes various types of derivative financial instruments, including swaps and collars, 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.

- 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 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 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 on 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 at June 30, 2018, the Company would not have experienced a loss.

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Commodity Derivative Contracts

The Company has various oil and natural gas derivative contracts that extend through December 31, 2020, summarized as follows:

	NYMEX WTI					
	Fixed Swaps		Three-Way Collars			
	Hedge Position (Bbls)	Weighted Avg Strike Price	Hedge Position (Bbls)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Weighted Avg Sub-Floor Price
Quarter Ended:						
June 30, 2018	159,250	$ 52.50	182,000	$ 60.65	$ 50.00	$ 40.00
September 30, 2018(1)	175,720	$ 57.23	184,000	$ 59.93	$ 50.00	$ 40.00
December 31, 2018(1)	313,720	$ 58.59	46,000	$ 56.70	$ 50.00	$ 40.00
March 31, 2019(1)	171,000	$ 66.48	180,000	$ 63.14	$ 53.75	$ 43.75
June 30, 2019(1)	133,900	$ 64.86	182,000	$ 63.14	$ 53.75	$ 43.75
September 30, 2019(1)	46,000	$ 62.96	184,000	$ 63.14	$ 53.75	$ 43.75
December 31, 2019(1)	46,000	$ 61.43	184,000	$ 63.14	$ 53.75	$ 43.75
March 31, 2020(1)	—	$ —	91,000	$ 65.75	$ 50.00	$ 40.00
June 30, 2020(1)	—	$ —	91,000	$ 65.75	$ 50.00	$ 40.00
September 30, 2020(1)	—	$ —	92,000	$ 65.75	$ 50.00	$ 40.00
December 31, 2020(1)	—	$ —	92,000	$ 65.75	$ 50.00	$ 40.00

	NYMEX HENRY HUB					
	Fixed Swaps		Three-Way Collars			
	Hedge Position (MMBtu)	Weighted Avg Strike Price	Hedge Position (MMBtu)	Weighted Avg Ceiling Price	Weighted Avg Floor Price	Weighted Avg Sub-Floor Price
Quarter Ended:						
June 30, 2018	1,155,000	$ 2.82	1,365,000	$ 3.40	$ 3.00	$ 2.50
September 30, 2018(1)	2,116,000	$ 2.84	1,380,000	$ 3.40	$ 3.00	$ 2.50
December 31, 2018(1)	2,055,000	$ 2.95	1,380,000	$ 3.40	$ 3.00	$ 2.50
March 31, 2019(1)	1,980,000	$ 3.01	1,350,000	$ 3.40	$ 3.00	$ 2.50

(1) Positions shown represent open commodity derivative contract positions as of June 30, 2018.

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 interim condensed consolidated balance sheets for the periods presented (in thousands):

Type	Balance Sheet Location (1)	June 30, 2018	December 31, 2017
Gas swaps	Derivative financial instruments — current assets	$ —	$ 821
Oil collars	Derivative financial instruments — current assets	—	(760)
Gas collars	Derivative financial instruments — current assets	—	701
Total derivative financial instruments — current assets		**$ —**	**$ 762**
Oil swaps	Derivative financial instruments — current liabilities	$ (6,209)	$ (3,679)
Gas swaps	Derivative financial instruments — current liabilities	(396)	—
Oil collars	Derivative financial instruments — current liabilities	(5,220)	(370)
Gas collars	Derivative financial instruments — current liabilities	276	616
Total derivative financial instruments — current liabilities		**$ (11,549)**	**$ (3,433)**
Oil swaps	Derivative financial instruments — noncurrent liabilities	$ (162)	$ (523)
Oil collars	Derivative financial instruments — noncurrent liabilities	(3,131)	(39)
Total derivative financial instruments — noncurrent liabilities		**$ (3,293)**	**$ (562)**

Total derivative fair value at period end	$ (14,842)	$ (3,233)

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(1) The fair values of commodity derivative instruments reported in the Company's unaudited interim 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 as well as the gross recognized derivative assets, liabilities and amounts offset in the unaudited interim condensed consolidated balance sheets for the periods presented (in thousands):

		June 30, 2018		
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	$ 1,366	$ (1,366)	$ —
Commodity contracts	Derivative financial instruments — noncurrent	2,469	(2,469)	—
		$ 3,835	**$ (3,835)**	**$ —**
Derivative Liabilities:				
Commodity contracts	Derivative financial instruments — current	$ (12,915)	$ 1,366	$ (11,549)
Commodity contracts	Derivative financial instruments — noncurrent	(5,762)	2,469	(3,293)
		$ (18,677)	**$ 3,835**	**$ (14,842)**

		December 31, 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	$ 3,479	$ (2,717)	$ 762
Commodity contracts	Derivative financial instruments — noncurrent	905	(905)	—
		$ 4,384	**$ (3,622)**	**$ 762**
Derivative Liabilities:				
Commodity contracts	Derivative financial instruments — current	$ (6,150)	$ 2,717	$ (3,433)
Commodity contracts	Derivative financial instruments — noncurrent	(1,467)	905	(562)
		$ (7,617)	**$ 3,622**	**$ (3,995)**

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 in gains (losses) on commodity derivative contracts—net within revenues in the unaudited interim condensed consolidated statements of operations.

The following table presents net cash received or net cash paid for the settlement of commodity derivative contracts and unrealized net gains or unrealized net losses 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 June 30,		For the Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Net cash received (paid) for commodity derivative contracts	$ (3,518)	$ 2,429	$ (3,677)	$ 3,240
Unrealized net gains (losses)	(7,830)	5,064	(11,610)	9,118
Gains on commodity derivative contracts—net	**$ (11,348)**	**$ 7,493**	**$ (15,287)**	**$ 12,358**

Net cash received (paid) for commodity derivative contracts, as presented in the table above, represent realized gains (losses) related to the Company's derivative instruments. In addition to these 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 cash 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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6. Property and Equipment

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

	June 30, 2018	December 31, 2017
	(in thousands)	
Oil and gas properties, on the basis of full-cost accounting:		
Proved properties	$ 778,741	$ 765,308
Unproved properties not being amortized	4,383	7,065
Other property and equipment	6,243	6,508
Less accumulated depreciation, depletion, amortization and impairment	(235,948)	(204,419)
Net property and equipment	**$ 553,419**	**$ 574,462**

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 six months ended June 30, 2018 and 2017, the Company capitalized the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Internal costs capitalized to oil and gas properties (1)	$ 922	$ 1,412	$ 1,817	$ 3,005

(1) Inclusive of $0.3 million and $0.5 million of qualifying share-based compensation expense for the three months ended June 30, 2018 and 2017, respectively. For the six months ended June 30, 2018 and 2017, inclusive of $0.5 million and $1.2 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 six months ended June 30, 2018 and 2017, the Company disposed of certain oil and gas equipment for cash proceeds of $0.4 million and $1.4 million, respectively, which were reflected as reduction of oil and gas properties with no gain or loss recognized. In addition, during the six months ended June 30, 2018, the Company disposed of its Anadarko Basin assets, which is discussed further below.

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 interim condensed consolidated statements of operations. While the Company did not record any impairments of oil and gas properties during the three or six months ended June 30, 2018 or 2017, the Company recorded impairments of oil and gas properties during the year ended December 31, 2017, the period January 1, 2016 through October 20, 2016 and the year ended December 31, 2015.

Depreciation, depletion and amortization 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 depreciation, depletion, amortization 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 periods presented:

	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in thousands)		(per Boe)		(in thousands)		(per Boe)	
Depletion expense	$ 15,898	$ 15,367	$ 8.97	$ 7.51	$ 30,520	$ 30,120	$ 8.71	$ 7.23
Depreciation on other property and equipment	586	592	0.33	0.29	1,177	1,181	0.34	0.28
Depreciation, depletion, and amortization	**$ 16,484**	**$ 15,959**	**$ 9.30**	**$ 7.80**	**$ 31,697**	**$ 31,301**	**$ 9.05**	**$ 7.51**

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 six months ended June 30, 2018 or 2017. Unproved property was $4.4 million and $7.1 million at June 30, 2018 and December 31, 2017, 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 two to ten years. Maintenance and repairs are charged to expense as incurred, while renewals and betterments are capitalized.

Sale of Anadarko Basin Assets

On May 31, 2018, the Company closed on the sale of its Anadarko Basin assets for $58.0 million in cash ($54.4 million, net of closing adjustments), subject to standard post-closing adjustments to occur within 120 days of closing. The net proceeds were reflected as a reduction of oil and natural gas properties, with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool. The Company used $50.0 million of the net proceeds from the sale of the Anadarko Basin assets to pay down a portion of outstanding borrowings under the Company's reserves-based revolving credit facility ("RBL") and retained the remainder for general corporate purposes.

7. Accrued Liabilities

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

	June 30, 2018	December 31, 2017
	(in thousands)	
Accrued oil and gas capital expenditures	$ 9,768	$ 9,081
Accrued revenue and royalty distributions	16,924	18,701
Accrued lease operating and workover expense	4,516	5,150
Accrued interest	162	108
Accrued taxes	2,278	2,758
Compensation and benefit related accruals	2,821	4,520
Other	3,858	2,524
Accrued liabilities	**$ 40,327**	**$ 42,842**

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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 are 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):

	Six Months Ended June 30,	
	2018	2017
Asset retirement obligations — beginning of period	$ 15,506	$ 14,200
Liabilities incurred	219	117
Revisions	—	—
Liabilities settled	(1)	(35)
Liabilities eliminated through asset sales	(8,698)	—
Current period accretion expense	547	559
Asset retirement obligations — end of period	**$ 7,573**	**$ 14,841**

9. Debt

Reserves-Based Revolving Credit Facility

At June 30, 2018 and December 31, 2017, the Company maintained an RBL with a borrowing base of $170.0 million. During the six months ended June 30, 2018, the Company paid down $100.0 million of its RBL utilizing $50.0 million of available cash on hand and $50.0 million of the net proceeds from the sale of its Anadarko Basin assets. At June 30, 2018 and December 31, 2017, the Company had $28.1 million and $128.1 million, respectively, drawn on the RBL and had outstanding letters of credit obligations totaling $1.9 million. As a result, at June 30, 2018, the Company had $140.0 million of availability on the RBL.

The RBL matures on September 30, 2020, and bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. At June 30, 2018, the weighted average interest rate was 8.0%, excluding amortization expense of deferred financing costs. Unamortized debt issuance costs of $1.0 million and $1.2 million associated with the RBL are included in other noncurrent assets on the unaudited interim condensed consolidated balance sheets at June 30, 2018 and December 31, 2017, respectively.

In addition to interest expense, the RBL 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.

The RBL, as amended, includes certain financial maintenance covenants that are required to be calculated on a quarterly basis for compliance purposes. These financial maintenance covenants include EBITDA to interest expense for the trailing four fiscal quarters of not less than 2.50:1.00 and a limitation of Total Net Indebtedness (as defined in the RBL) to EBITDA for the trailing four fiscal quarters of not more than 4.00:1.00.

In addition, the RBL contains various other covenants that, among other things, may restrict the Company's ability to: (i) incur additional indebtedness or guarantee indebtedness (ii) make loans and investments; (iii) pay dividends on capital stock and make other restricted payments, including the prepayment or redemption of other indebtedness; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with the Company's affiliates; (vii) acquire, consolidate or merge with another entity upon certain terms and conditions; (viii) sell all or substantially all of the Company's assets; (ix) prepay, redeem or repurchase certain debt; (x) alter the business the Company conducts and make amendments to the Company's organizational documents, (xi) enter into certain derivative transactions and (xii) enter into certain marketing agreements and take-or-pay arrangements.

The Company was in compliance with all debt covenants at June 30, 2018.

On April 19, 2018, 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 and subsequently divested, as discussed above.

The Company believes the carrying amount of the RBL at June 30, 2018, approximates, its fair value (Level 2) due to the variable nature of the RBL interest rate.

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10. Equity and Share-Based Compensation

Common Shares

Share Activity

The following table summarizes changes in the number of shares of common stock and treasury stock during the six months ended June 30, 2018:

	Common Stock	Treasury Stock(1)
Share count as of December 31, 2017	**25,272,969**	**(99,623)**
Common stock issued	113,135	—
Acquisition of treasury stock	—	(29,524)
Share count as of June 30, 2018	**25,386,104**	**(129,147)**

(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 October 21, 2016, 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 June 30, 2018, 1,892,511 Award Shares remain available for issuance under the terms of the 2016 LTIP.

Restricted Stock Units

At June 30, 2018, the Company had 491,943 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. During the six months ended June 30, 2018, 271,968 non-vested restricted stock units were issued to employees and non-employee directors. Restricted stock units granted to employees in 2018 under the 2016 LTIP vest ratably over a period of three years: one-third will vest on December 31, 2018, an additional one-third will vest on December 31, 2019, and the final one-third will vest on December 31, 2020. Restricted stock units granted to non-employee directors during 2018 vest on the first to occur of (i) December 31, 2018, (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 granted to employees and non-employee directors during 2018 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 six months ended June 30, 2018:

	Restricted Stock	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2017	**324,984**	$ 18.84
Granted	271,968	$ 14.24
Vested(1)	(105,009)	$ 19.63
Forfeited	—	$ —
Non-vested shares outstanding at June 30, 2018	**491,943**	$ 16.13

(1) Vested restricted stock units include 102,092 shares in which vesting was accelerated as a result of a reduction in workforce that occurred during the six months ended June 30, 2018.

Unrecognized expense as of June 30, 2018 for all outstanding restricted stock units under the 2016 LTIP Plan was $4.3 million and will be recognized over a weighted average period of 1.1 years.

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Stock Options

At June 30, 2018, the Company had 143,086 non-vested options outstanding pursuant to the 2016 LTIP. Stock Option Awards currently outstanding under 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. There were no issuances of stock options during the six months ended June 30, 2018.

The following table summarizes the Company's 2016 LTIP non-vested stock option activity for the six months ended June 30, 2018:

	Options	Range of Exercise Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)
Stock options outstanding at December 31, 2017	245,845		$ 19.66	8.3
Granted	—	$ —	$ —	—
Vested(1)	(102,759)	$ 19.08–19.66	$ 19.66	0.1
Forfeited	—	$ —	$ —	—
Stock options outstanding at June 30, 2018	143,086		$ 19.66	8.3
Vested and exercisable at end of period(2)	224,664	$ 19.08-20.97	$ 19.66	4.6

(1) Vested stock options include 102,092 options in which vesting was accelerated as a result of a reduction in workforce that occurred during the six months ended June 30, 2018.

(2) Vested and exercisable options at June 30, 2018, had no aggregate intrinsic value.

Unrecognized expense as of June 30, 2018 for all outstanding stock options under the 2016 LTIP Plan was $0.5 million and will be recognized over a weighted average period of 0.8 years.

Non-Employee Director Restricted Stock Units Containing a Market Condition

On November 23, 2016, the Company issued 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 (as defined in the 2016 LTIP) 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 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 Accounting Standards Codification 718 — *Stock Compensation* ("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 derived service period related to these awards ended in November of 2017. As such, changes in the fair value of the liability and related compensation expense of these awards are no longer recognized pro-rata over the period for which service has already been provided but rather are compensation cost in the period in which the changes occur. 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.

At June 30, 2018, the Company recorded a $0.4 million liability included within accrued liabilities on the unaudited interim condensed consolidated balance sheets related to the restricted stock units containing a market condition. The weighted-average fair value of the restricted stock units containing a market condition was $5.28 at June 30, 2018.

As of June 30, 2018, there was no unrecognized stock-based compensation expense related to market condition awards.

Chief Executive Officer ("CEO") Restricted Stock Units Containing a Market Condition

On November 1, 2017, the Company issued restricted stock units to its CEO that contain a market vesting condition. These restricted stock units will vest, if at all, based on the Company's total stockholder return for the performance period of October 25, 2017 through October 31, 2020. Market conditions under this grant are (i) with respect to 50% of the RSUs granted, the Company's cumulative total shareholder return ("TSR") which is defined as the change in the value of the stock over the performance period with the beginning and ending stock price based on a 20-day average stock price and (ii) with respect to the remaining 50% of the RSUs granted, the percentile rank of the Company's TSR compared to the TSR of the Peer Group over the performance period ("Relative TSR").

To the extent that actual TSR or Relative TSR for the performance period is between specified vesting levels, the portion of the RSUs that shall become vested based on actual and Relative TSR performance shall be determined on a pro-rata basis using straight-line interpolation; provided that the maximum portion of the RSUs that may become vested based on actual cumulative TSR or Relative TSR for the performance period shall not exceed 120% of the awards granted.

The RSUs issued to the CEO containing a market condition have a service period of three years. The share-based compensation costs related to the CEO restricted stock units containing a market condition recognized as general and administrative expense by the Company was $0.1 million and $0.2 million for the three and six months ended June 30, 2018. As of June 30, 2018, unrecognized stock-based compensation related to CEO RSUs containing a market condition was $1.2 million and will be recognized over a weighted-average period of 2.3 years.

Performance Stock Units Issued to Certain Members of Executive Management Containing a Market Condition

On March 1, 2018, the Company issued restricted stock units to certain members of executive management that contain a market vesting condition. These restricted stock units will vest, if at all, based on the Company's total stockholder return for the performance period of January 1, 2018 through December 31, 2020.

To the extent that the Relative TSR for the performance period is between specified vesting levels, the portion of the restricted stock units that become vested based on the Relative TSR performance shall be determined on a pro-rata basis using straight-line interpolation; provided that the maximum portion of the restricted stock units that may become vested based on the Relative TSR for the performance period shall not exceed 150% of the awards granted. In addition, if the Relative TSR for the Company is negative over the performance period, vesting of these performance stock units is limited to no more than 100%.

If a member of executive management terminates employment prior to vesting, the outstanding award is forfeited. Executive management restricted stock units with a market condition are subject to accelerated vesting in the event the executive's employment is terminated prior to vesting by the Company without "Cause" or by the participant with "Good Reason" (each, as defined in the 2016 LTIP) or due to the executive's death or disability. Upon a change in control (as defined in the 2016 LTIP), the compensation committee of the board of directors could (i) accelerate all or a portion of the award, (ii) cancel all of the award and pay cash, stock or combination equal to the change in control price, (iii) provide for the assumption or substitution or continuation by the successor company, (iv) certify to the extent to which the vesting conditions had been achieved prior to the conclusion of the performance period or (v) adjust restricted stock units to reflect the change in control.

These restricted stock awards are accounted for as equity awards under ASC 718 as the awards are settled in shares of the Company with no additional settlement options permitted. At the grant date, the Company estimated the fair value of this equity award. The compensation expense of this award each period is recognized by dividing the fair value of the total award 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 executives.

The restricted stock units issued to executive management containing a market condition have a service period of three years. The share-based compensation costs related to executive management's restricted stock units containing a market condition recognized as general and administrative expense by the Company was $0.1 million and $0.2 million for the three and six months ended June 30, 2018. As of June 30, 2018, unrecognized stock-based compensation related to executive management's restricted stock units containing a market condition was $1.1 million and will be recognized over a weighted-average period of 2.5 years.

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11. Income Taxes

On December 22, 2017, the Tax Act was enacted into law and the new legislation contains several key tax provisions that affected the Company, primarily a reduction of the corporate income tax rate to 21% effective January 1, 2018. The Company was required to recognize the effect of the tax law changes in the period of enactment. The Company re-measured its U.S. deferred tax assets and liabilities as well as reassessed the net realizability of its deferred tax assets and liabilities. In December 2017, the SEC staff issued SAB 118, which allows the Company to record provisional amounts during a measurement period not to extend beyond one year of the enactment date. As the Tax Act was passed late in the fourth quarter of 2017, ongoing guidance from the Department of Treasury and state agencies and accounting interpretation is expected to be issued over the next 6 months. Therefore, for the six months ended June 30, 2018, the Company considered the accounting of certain items to be incomplete due to forthcoming guidance and the ongoing analysis of final year-end data and tax positions.

For the six months ended June 30, 2018, the Company has estimated deductions of $19.2 million associated with the full expensing of the costs of qualified property that were incurred and placed into service during the period from January 1, 2018 to June 30, 2018. The Company continues to analyze assets placed into service after September 27, 2017, but not qualifying for full expensing as a result of being acquired under an agreement entered into prior to that date. In addition, further guidance and analysis is required in order to review the terms of the Company's compensation plans and agreements and assess the impact of transitional guidance related to IRC Section 162(m) on awards granted prior to November 2, 2017, subject to the grandfather provisions. As a result, the Company has not adjusted certain tax items previously reported on its financial statements for IRC Section 162(m) until the Company is able to obtain sufficient information to make a reasonable estimate of the effects of the Tax Act. The Company expects to complete its analysis within the measurement period in accordance with SAB No. 118.

For the six months ended June 30, 2018, the Company recorded no income tax expense or benefit. The significant difference between its effective tax rate and the federal statutory income tax rate of 21% is primarily due to the effect of changes in the Company's valuation allowance. During the six months ended June 30, 2018, the Company's valuation allowance decreased by $0.7 million from December 31, 2017, bringing the total valuation allowance to $119.4 million at June 30, 2018. 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. Income Per Share

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

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	(in thousands, except per share amounts)		(in thousands, except per share amounts)	
Net Income (Loss):				
Net income (loss)	$ (1,542)	$ 13,742	$ 2,461	$ 32,227
Participating securities—non-vested restricted stock	—	(360)	(68)	(897)
Basic and diluted income (loss)	**$ (1,542)**	**$ 13,382**	**$ 2,393**	**$ 31,330**
Common Shares:				
Common shares outstanding — basic (1)	**25,332**	**25,093**	**25,316**	**25,053**
Dilutive effect of potential common shares	—	—	—	—
Common shares outstanding — diluted	**25,332**	**25,093**	**25,316**	**25,053**
Net Income (Loss) Per Share:				
Basic	**$ (0.06)**	**$ 0.53**	**$ 0.09**	**$ 1.25**
Diluted	**$ (0.06)**	**$ 0.53**	**$ 0.09**	**$ 1.25**
Antidilutive stock options (2)	**500**	**529**	**500**	**578**
Antidilutive warrants (3)	**6,626**	**6,626**	**6,626**	**6,626**

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(1) Weighted-average common shares outstanding for basic and diluted income per share purposes includes 9,407 and 17,533 shares of common stock that, while not issued and outstanding at June 30, 2018 or 2017, respectively, are required by the First Amended Joint Chapter 11 Plan of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate as filed on September 28, 2016 to be issued. Weighted-average common shares outstanding for basic and diluted income per share purposes also includes 57,856 director shares that vested as of December 31, 2017, but final issuance of the vested shares was deferred by the non-employee directors until 2020.

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

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

13. Related Party Transactions

During 2017, the Company entered into an arrangement with EcoStim Energy Solutions, Inc. ("EcoStim") for well stimulation and completion services. EcoStim is an affiliate of Fir Tree Inc. who is a holder of the Company's outstanding common stock. The Company had $2.1 million included in accounts payable in the Company's unaudited interim condensed consolidated balance sheets at December 31, 2017 to EcoStim that was paid during the six months ended June 30, 2018. For the three and six months ended June 30, 2017, the Company paid approximately $1.4 million to EcoStim Energy Solutions, Inc. for services provided.

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.

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 June 30, 2018 and December 31, 2017, the Company's total accrual for all loss contingencies was $1.1 million.

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, 2017, 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 14, 2018, as well as the unaudited interim condensed consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q and our quarterly report on Form 10-Q for the quarter ended March 31, 2018 filed with the SEC on May 10, 2018.

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," and similar expressions 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;
- 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;
- 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;
- 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 currently focused on exploration and production activities in the Mississippian Lime. 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.

Recent Developments

Sale of Anadarko Basin Assets

On May 31, 2018, we closed on the sale of our Anadarko Basin assets for $58.0 million in cash ($54.4 million, net of closing adjustments), subject to standard post-closing adjustments to occur within 120 days of closing. The net proceeds were reflected as a reduction of oil and natural gas properties, with no gain or loss recognized as the sale did not result in a significant alteration of the full cost pool. We used $50.0 million of the net proceeds from the sale of the Anadarko Basin assets to pay down a portion of outstanding borrowings under our RBL and retained the remainder for general corporate purposes. The Anadarko Basin assets in Texas and Oklahoma were excluded from the April 2018 redetermination of our $170.0 million borrowing base, as discussed above.

Operations Update

Mississippian Lime

The following table presents our average daily production from our Mississippian Lime asset for the periods presented:

	Three Months Ended June 30, 2018	Three Months Ended March 31, 2018	Increase in Production
Average daily production:			
Oil (Bbls)	4,833	4,564	5.9%
Natural gas liquids (Bbls)	3,995	3,644	9.6%

Natural gas (Mcf)	50,246	43,857	14.6%
Net Boe/day	**17,202**	**15,518**	10.9**%**

The following table shows our total number of horizontal wells spud and brought into production in the Mississippian Lime asset during the second quarter of 2018:

	Total Number of Gross Horizontal Wells Spud (1)	Total Number of Gross Horizontal Wells Brought into Production
Mississippian Lime	4	8

(1) We had one rig drilling in the Mississippian Lime horizontal well program at June 30, 2018. Of the four wells spud, two were producing, one was awaiting completion and one was being drilled at quarter-end. In addition, three wells spud during the three months ended March 31, 2018 were awaiting completion at June 30, 2018.

In the second quarter of 2018, we incurred approximately $39.2 million of operational capital expenditures in the Mississippian Lime basin.

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Anadarko Basin

The following table presents our average daily production from our Anadarko Basin asset for the periods presented:

	Two Months Ended May 31, 2018(1)	Three Months Ended March 31, 2018	Decrease in Production
Average daily production:			
Oil (Bbls)	1,110	1,207	(8.0)%
Natural gas liquids (Bbls)	946	1,065	(11.2)%
Natural gas (Mcf)	7,956	8,671	(8.2)%
Net Boe/day	**3,382**	**3,717**	**(9.0)%**

(1) We closed on the sale of our Anadarko Basin assets on May 31, 2018. As a result, average daily production as presented in the table above is for the period April 1, 2018 through May 31, 2018.

We did not spud any wells in our Anadarko Basin asset and did not have any operated drilling rigs in the area during the second quarter of 2018.

Capital Expenditures

During the three and six months ended June 30, 2018, we incurred operational capital expenditures of $39.2 million and $71.4 million, respectively, which consisted of the following:

	For the Three Months Ended June 30, 2018	For the Six Months Ended June 30, 2018
Drilling and completion activities	$ 36,651	$ 67,405
Acquisition of acreage and seismic data	2,515	3,952
Operational capital expenditures incurred	**$ 39,166**	**$ 71,357**
Capitalized G&A, office, ARO & other	969	2,189
Capitalized interest	114	191
Total capital expenditures incurred	**$ 40,249**	**$ 73,737**

Operational capital expenditures by area were as follows:

	For the Three Months Ended June 30, 2018	For the Six Months Ended June 30, 2018
Mississippian Lime	$ 39,192	$ 71,397
Anadarko Basin	(26)	(40)
Total operational capital expenditures incurred	**$ 39,166**	**$ 71,357**

We are currently operating one drilling rig in the Mississippian Lime asset. Based upon a one rig program, we would expect to invest between $100.0 million to $110.0 million in this area during the year ended December 31, 2018.

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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 six months ended June 30, 2018, the results of our full cost "ceiling test" did not require us to recognize impairments of our oil and gas properties. However, we recorded impairments of oil and gas properties during the year ended December 31, 2017, the period January 1, 2016 through October 20, 2016 and the year ended December 31, 2015. Impairments can result from multiple factors, such as commodity pricing, changes in our strategic drilling plans, increased capital costs, well performance that is below expectations or higher operating costs. Our industry is dynamic and while we have not experienced impairments for the three and six months ended June 30, 2018, we may be required to record impairments in the future based upon changes in the factors discussed above. While an impairment does not impact cash flow from operating activities or liquidity, such adjustments do decrease our net income and shareholders' equity.

We dispose of large volumes of saltwater produced in conjunction with 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 continues to be a concern that the injection of saltwater contributes to seismic activity in certain areas of Oklahoma where we operate. The Oil and Gas Conservation Division ("OGCD") of the Oklahoma Corporation Commission ("OCC") established injection limits for additional wells in the Arbuckle formation, including 10 that we operate, 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. The OGCD has since issued several directives for disposal well shut-in and and volume reductions in certain areas following seismic activity. While our current plans are for future disposal wells to inject into formations other than the Arbuckle and we currently operate 11 such non-Arbuckle formation disposal wells, we continue to utilize wells that dispose into the Arbuckle formation. We have timely met and satisfied all requests of the OCC regarding changes and/or reductions in disposal capacity in our operated disposal wells, all while maintaining our production base without any negative material impact thereto. We believe 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 saltwater 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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Results of Operations

The following tables summarize our revenues for the periods indicated (in thousands):

	Crude Oil	Natural Gas	NGLs	Total
Revenues for the three months ended June 30, 2017	$ 27,271	$ 15,253	$ 9,730	$ 52,254
Changes due to volumes	(3,553)	(1,801)	(1,658)	(7,012)
Changes due to price(1)	10,484	(6,670)	3,821	7,635

Revenues for the three months ended June 30, 2018	$ 34,202	$ 6,782	$ 11,893	$ 52,877

	Crude Oil	Natural Gas	NGLs	Total
Revenues for the six months ended June 30, 2017	$ 58,307	$ 32,351	$ 20,924	$ 111,582
Changes due to volumes	(8,868)	(5,142)	(3,573)	(17,583)
Changes due to price (1)	17,177	(12,090)	5,580	10,667
Revenues for the six months ended June 30, 2018	$ 66,616	$ 15,119	$ 22,931	$ 104,666

(1) Changes due to price for natural gas for the three and six months ended June 30, 2018, includes $3.4 million and $6.4 million, respectively, of gathering and transportation expense that as a result of ASC 606, are being net against revenues in the unaudited interim condensed consolidated statements of operations. Oil, NGLs and natural gas included $0.1 million and $0.2 million, respectively, for the three and six months ended June 30, 2018, of lease operating expenses that are now being netted against revenues in the unaudited interim condensed consolidated statements of operations. See Note 3 to the financial statements included in “Part I. Financial Information — Item 1. Financial Statements” of this report for further details.

Oil, NGLs and Natural Gas Pricing

The following tables set forth information regarding average realized sales prices for the periods indicated (per BOE):

	Crude Oil		NGLs		Natural Gas	
	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
Average sales price exclusive of realized derivatives and certain deductions from revenue	$ 67.42	$ 46.73	$ 28.28	$ 19.16	$ 2.01	$ 2.66
Realized derivatives	(7.44)	3.15	—	—	0.05	0.10
Average sales price with realized derivatives exclusive of certain deductions from revenue	$ 59.98	$ 49.88	$ 28.28	$ 19.16	$ 2.06	$ 2.76
Certain deductions from revenue (1)	(0.03)		(0.04)		(0.67)	
Average sales price inclusive of realized derivatives and certain deductions from revenue (1)	$ 59.95		$ 28.24		$ 1.39	

(1) Average realized prices for the three months ended June 30, 2017, were based upon revenues as presented under ASC 605. As a result, the appropriate realized price for comparison purposes with June 30, 2018, is the average sale price exclusive of realized derivatives and certain deductions from revenue. See Note 3 to the financial statements included in “Part I. Financial Information — Item 1. Financial Statements” of this report for further details.

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	Crude Oil		NGLs		Natural Gas	
	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Average sales price exclusive of realized derivatives and certain deductions from revenue	$ 64.89	$ 48.16	$ 27.19	$ 20.53	$ 2.21	$ 2.78
Realized derivatives	(5.11)	1.92	—	—	0.16	0.08
Average sales price with realized derivatives exclusive of certain deductions from revenue	$ 59.78	$ 50.08	$ 27.19	$ 20.53	$ 2.37	$ 2.86
Certain deductions from revenue (1)	(0.02)		(0.05)		(0.66)	
Average sales price inclusive of realized derivatives and certain deductions from revenue (1)	$ 59.76		$ 27.14		$ 1.71	

(1) Average realized prices for the six months ended June 30, 2017, were based upon revenues as presented under ASC 605. As a

result, the appropriate realized price for comparison purposes with June 30, 2018, is the average sale price exclusive of realized derivatives and certain deductions from revenue. See Note 3 to the financial statements included in “Part I. Financial Information — Item 1. Financial Statements” of this report for further details.

Oil, NGLs and Natural Gas Production

	For the Three Months Ended June 30, 2018	For the Three Months Ended June 30, 2017	% Change	For the Six Months Ended June 30, 2018	For the Six Months Ended June 30, 2017	% Change(1)
PRODUCTION DATA:						
Oil (Bbls/d)						
Mississippian Lime	4,833	4,938	(2.1)%	4,699	5,269	(10.8)%
Anadarko Basin(1)	1,110	1,475	(24.7)%	1,168	1,420	(17.7)%
Natural gas liquids (Bbls/d)						
Mississippian Lime	3,995	4,466	(10.5)%	3,821	4,526	(15.6)%
Anadarko Basin(1)	946	1,115	(15.2)%	1,017	1,104	(7.9)%
Natural gas (Mcf/d)						
Mississippian Lime	50,246	53,246	(5.6)%	47,083	54,653	(13.9)%
Anadarko Basin(1)	7,956	9,735	(18.3)%	8,365	9,565	(12.5)%
Combined (Boe/d)						
Mississippian Lime	17,202	18,278	(5.9)%	16,367	18,905	(13.4)%
Anadarko Basin(1)	3,382	4,212	(19.7)%	3,579	4,118	(13.1)%

(1) We closed on the sale of our Anadarko Basin assets on May 31, 2018. As a result, average daily production as presented in the table above for the Anadarko Basin is for the period April 1, 2018 through May 31, 2018.

Oil Revenues

Oil volumes sold decreased for the three and six months ended June 30, 2018, primarily due to lower production as a result of reduced drilling activity and natural decline. Average oil sales prices, without realized derivatives and certain deductions, increased primarily as a result of a significant increase in prevailing market prices.

NGLs Revenues

NGLs volumes sold decreased for the three and six months ended June 30, 2018, primarily due to lower production as a result of reduced drilling activity and natural decline. Average NGLs sales prices, without realized derivatives and certain deductions, increased as a result of higher oil prices, which correlate with NGLs pricing.

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Natural Gas Revenues

Natural gas volumes sold decreased for the three and six months ended June 30, 2018, primarily due to lower production as a result of reduced drilling activity and natural decline. Average natural gas sales prices, without realized derivatives and gathering and transportation expenses, decreased due to lower prevailing index prices at our delivery points. Beginning January 1, 2018, we adopted ASC 606, and as a result, \$3.4 million and \$6.4 million in gathering and transportation expenses for the three and six months ended June 30, 2018, respectively, are now being netted against gas sales revenue in the unaudited interim condensed consolidated statements of operations. See Note 3 to the financial statements included in “Part I. Financial Information — Item 1. Financial Statements” of this report for further details.

Gains/Losses on Commodity Derivative Contracts—Net

A summary of our open commodity derivative positions is included in Note 5 to the financial statements included in “Part I. Financial Information — Item 1. Financial Statements” of this report. The following tables provide financial information associated with our oil and natural gas hedges for the periods indicated (in thousands):

	For the Three Months Ended June 30, 2018	For the Three Months Ended June 30, 2017	For the Six Months Ended June 30, 2018	For the Six Months Ended June 30, 2017
Cash receipts (payments on settlement)				
Oil derivatives	$ (3,776)	$ 1,839	$ (5,252)	$ 2,328
Natural gas derivatives	258	590	1,575	912
Total cash settlements	**$ (3,518)**	**$ 2,429**	**$ (3,677)**	**$ 3,240**
Gains (losses) due to fair value changes				
Oil derivatives	$ (6,986)	$ 3,312	$ (9,390)	$ 6,543

Natural gas derivatives		(844)		1,752		(2,220)		3,575
Total gains (losses) on fair value changes	**$**	**(7,850)**	**$**	**5,064**	**$**	**(11,610)**	**$**	**9,118**
Gains (losses) on commodity derivative contracts—net	**$**	**(11,348)**	**$**	**7,493**	**$**	**(15,287)**	**$**	**12,358**

Our mark-to-market ("MTM") derivative positions moved to unrealized losses for the three and six months ended June 30, 2018, from unrealized gains for the comparable periods in 2017.

Cash settlements, as presented in the table above, represent realized gains (losses) related to our derivative instruments. In addition to cash settlements, we also recognize fair value changes on our 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.

Expenses

	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in thousands)		(per Boe)		(in thousands)		(per Boe)	
EXPENSES:								
Lease operating and workover	$ 16,952	$ 16,559	$ 9.57	$ 8.09	$ 31,760	$ 32,411	$ 9.07	$ 7.78
Gathering and transportation	67	3,641	0.04	1.78	124	7,328	0.04	1.76
Severance and other taxes	2,776	1,695	1.57	0.83	5,638	3,816	1.61	0.92
Asset retirement accretion	250	283	0.14	0.14	547	559	0.16	0.13
Depreciation, depletion, and amortization	16,484	15,959	9.30	7.80	31,697	31,301	9.05	7.51
Impairment of oil and gas properties	—	—	—	—	—	—	—	—
General and administrative	5,190	7,572	2.93	3.70	15,047	15,847	4.30	3.80
Advisory fees	850	—	0.48	—	850	—	0.24	—
Total expenses	**$ 42,569**	**$ 45,709**	**$ 24.03**	**$ 22.34**	**$ 85,663**	**$ 91,262**	**$ 24.47**	**$ 21.90**

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Lease Operating and Workover

Lease operating and workover expenses increased $0.4 million during the three months ended June 30, 2018. Lease operating and workover expense, after being normalized for the Lincoln County divestiture and the adoption of ASC 606, increased $1.6 million primarily related to increased workover activity. Lease operating and workover expense decreased $0.7 million during the six months ended June 30, 2018. Lease operating and workover expense, after being normalized for the Greer Road insurance reimbursement, the Lincoln County divestiture and the adoption of ASC 606, decreased $0.2 million.

Gathering and Transportation

Gathering and transportation expenses decreased for the three and six months ended June 30, 2018, primarily as a result of our adoption of ASC 606 on January 1, 2018. As a result, $3.4 million and $6.4 million in gathering and transportation expenses for the three and six months ended June 30, 2018, are reflected as a decrease in oil, NGLs and natural gas sales in the unaudited interim condensed consolidated statements of operations. Gathering and transportation, excluding adjustments for ASC 606, decreased $0.2 million and $0.8 million for the three and six months ended June 30, 2018, due to a decrease in natural gas production in our Mississippian Lime asset.

Severance and Other Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
Total oil, NGLs and natural gas sales	**$ 52,877**	**$ 52,254**	**$ 104,666**	**$ 111,582**
Severance taxes	2,655	1,471	5,336	3,368
Ad valorem and other taxes	121	224	302	448
Severance and other taxes	**$ 2,776**	**$ 1,695**	**$ 5,638**	**$ 3,816**
Severance taxes as a percentage of sales	**5.0%**	**2.8%**	**5.1%**	**3.0%**
Severance and other taxes as a percentage of sales	**5.2%**	**3.2%**	**5.4%**	**3.4%**

Severance and other taxes increased for the three and six months ended June 30, 2018, respectively, compared to to prior periods in 2017. Severance taxes as a percentage of sales increased for the three and six months ended June 30, 2018, due to legislation changes in the State of Oklahoma that increased incentive tax rates on production from 1% to 4% effective July 1, 2017, and 4% to 7% effective in December of 2017. The adoption of ASC 606 on January 1, 2018, and the inclusion of $3.4 million and $6.4 million of gathering and transportation expenses in oil, NGLs and natural gas sales for the three and six months ended June 30, 2018, also impacted the severance and other taxes rate by 0.3% and 0.4%, respectively, compared to the same periods in 2017.

Additionally, in March 2018, the State of Oklahoma passed legislation to further amend the gross production incentive tax rate for wells drilled beginning July 1, 2015, from 2.0% to 5.0%. The initial 2.0% rate is effective for the first thirty-six months of production and moves to 7.0% thereafter. This legislation will increase the incentive tax rate to 5.0% for all new and existing wells that currently qualify for the 2.0% incentive tax rate for July 2018 production.

Depreciation, Depletion and Amortization

On November 1, 2017, David Sambrooks was appointed President and Chief Executive Officer of the Company. Upon the appointment of Mr. Sambrooks, we began a strategic review of all areas of operations. This review was completed during the fourth quarter of 2017 and our strategy was refined to add further focus to optimizing free cash flows and keeping leverage to a minimum. As a result, in December of 2017 we decreased our current drilling activity from two drilling rigs to one drilling rig. Further, the five-year development plan was revised from a two-rig program to a one rig program. This change in strategy (reduced 5-year drilling activity) led to a reduction in our undeveloped proved inventory under SEC guidelines. Depreciation, depletion and amortization and depreciation, depletion and amortization per BOE increased for the three and six months ended June 30, 2018 primarily due to this decrease in our proved reserves volumes.

General and Administrative ("G&A")

G&A expenses decreased for the three and six months ended June 30, 2018, primarily due to a reduction in salaries and wages of $1.0 million and $1.2 million, and a reduction in trailing costs incurred related to our bankruptcy of $1.7 million and $2.3 million. During the six months ended June 30, 2018, G&A was also impacted by increased employee severance costs of $1.6 million as a result of a reduction-in-force that occurred during January 2018, as well as $2.6 million related to our review of various strategic options. These increases during the six months ended June 30, 2018 were partially offset by $1.6 million in lower stock compensation expense.

Other Income (Expense)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)		(in thousands)	
OTHER EXPENSE				
Interest income	$ 5	$ —	$ 24	$ —
Interest expense	(1,308)	(1,862)	(3,104)	(3,682)
Amortization of deferred financing costs	(108)	(89)	(216)	(169)
Amortization of deferred gain	—	—	—	—
Capitalized interest	114	723	191	1,646
Interest expense—net of amounts capitalized	(1,302)	(1,228)	(3,129)	(2,205)
Total other income (expense)	**$ (1,297)**	**$ (1,228)**	**$ (3,105)**	**$ (2,205)**

Interest Expense

Interest expense decreased for the three and six months ended June 30, 2018, as a result of the average outstanding balance under our RBL decreasing by $62.9 million and $31.2 million compared to the same periods in 2017. In March of 2018, we paid down $50.0 million on our RBL using cash on hand and additionally paid down $50.0 million during June 2018 using proceeds from the sale of our Anadarko assets, as mentioned above. Total interest expense capitalized to oil and gas properties decreased for the three and six months ended June 30, 2018, due to a $23.9 million decrease in the carrying amount of our unproved property year over year.

Provision for Income Taxes

We recorded no income tax expense or benefit for the three and six months ended June 30, 2018 or 2017, respectively, due to the change in our valuation allowance recorded against our net deferred tax assets. Our valuation allowance was $119.4 million and $148.2 million for the three and six months ended June 30, 2018 and 2017, respectively.

Liquidity and Capital Resources

Overview

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

	June 30, 2018	December 31, 2017
Cash and cash equivalents	$ 6,256	$ 68,498

Net working capital (deficit)	(27,188)	48,866
Total long-term debt	28,059	128,059
Total stockholders' equity	491,991	485,587
Available borrowing capacity	140,000	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, cash on hand and cash available from borrowings under the RBL will be our primary sources of liquidity although we may seek to supplement our liquidity through divestitures, additional or refinanced 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. Volatility in commodity prices also impacts estimated quantities of proved reserves. Our longer term operating cash flows are dependent upon reserve replacement and the level of costs required for ongoing operations. We are required to make investments to fund activity necessary to offset the inherent declines in production and proved crude oil and natural gas reserves. Our ability to maintain and grow reserves and production is highly dependent on the success of our drilling program and our ability to add reserves economically. 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 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.

Significant Sources of Capital

RBL

At June 30, 2018, in addition to cash on hand of $6.3 million, we maintained the RBL. The RBL has a current borrowing base of $170.0 million. At June 30, 2018, we had $28.1 million drawn on the RBL and outstanding letters of credit obligations totaling $1.9 million. As a result, at June 30, 2018, we had $140.0 million of availability on the RBL.

The RBL matures on September 30, 2020, and borrowings thereunder are secured by (i) first-priority mortgages on at least 90% of the our oil and gas properties, (ii) all other presently owned or after-acquired property (including but not limited to as-extracted collateral, accounts receivable, inventory, equipment, general intangibles, investment property, intellectual property, real property and the proceeds of the foregoing) and (iii) a perfected pledge on all equity interests. The RBL bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. For the three months ended June 30, 2018, the weighted average interest rate was 8.0%, excluding amortization expense of deferred financing costs.

In addition to interest expense, the RBL 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 April 19, 2018, our borrowing base was redetermined at the existing amount of $170.0 million. The Anadarko Basin assets in Texas and Oklahoma were excluded from the redetermination of the borrowing base.

Debt Covenants

The RBL as amended, contains various other financial covenants, including an EBITDA to interest expense coverage ratio limitation of not less than 2.50:1.00 and a ratio limitation of Total Net Indebtedness (as defined in the RBL) to EBITDA of not more than 4.00:1.00.

In addition, the RBL contains various other covenants that, among other things, may restrict our ability to: (i) incur additional indebtedness or guarantee indebtedness (ii) make loans and investments; (iii) pay dividends on capital stock and make other restricted payments, including the prepayment or redemption of other indebtedness; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with our affiliates; (vii) acquire, consolidate or merge with another entity upon certain terms and conditions; (viii) sell all or substantially all of our assets; (ix) prepay, redeem or repurchase certain debt; (x) alter the business we conduct and make amendments to our organizational documents, (xi) enter into certain derivative transactions and (xii) enter into certain marketing agreements and take-or-pay arrangements.

As of June 30, 2018, we were in compliance with our debt covenants.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our 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 interim 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):

	For the Six Months Ended June 30, 2018	For the Six Months Ended June 30, 2017
Net cash provided by operating activities	$ 49,292	$ 63,177
Net cash used in investing activities	(11,056)	(53,019)
Net cash used in financing activities	(100,478)	(997)
Net change in cash	**$ (62,242)**	**$ 9,161**

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Cash flows provided by operating activities

Net cash provided by operating activities was $49.3 million and $63.1 million for the six months ended June 30, 2018 and 2017, respectively. The decrease in net cash provided by operating activities was primarily the result of a $6.8 million decrease in revenues from contracts with customers, payments made for the settlement of certain derivatives of $3.7 million as compared to receipts of derivative settlements of $3.2 million.

Cash flows used in investing activities

Net cash used in investing activities of $11.1 million and $53.0 million for the six months ended June 30, 2018 and 2017, respectively. Substantially all of our capital spend is invested into our Mississippi Lime asset. The decrease in cash used in investing activities is due to the sale of our Anadarko Basin assets in May 2018 for $58.0 million in cash ($54.4 million, net of closing adjustments), subject to standard post-closing adjustments to occur within 120 days of closing.

Cash flows provided by financing activities

Net cash used in financing activities was $100.5 million and $1.0 million for the six months ended June 30, 2018 and 2017, respectively. During the six months ended June 30, 2018, we paid down $100.0 million on the RBL, as well as, repurchased $0.5 million of restricted stock for tax withholdings related to stock compensation vestings.

Critical Accounting Policies and Estimates

When used in the preparation of our unaudited interim 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 condensed consolidated financial position, results of operations and cash flows.

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, 2017. There have been no changes to our critical accounting policies other than discussed below.

Revenue Recognition

On January 1, 2018, we adopted ASC 606, using the modified retrospective method of transition. The primary impact to our revenues as a result of the adoption of ASC 606 is the netting of certain deductions and costs against revenue instead of the historical practice of presenting such expenses gross in gathering and transportation.

Oil, NGLs and natural gas revenues are recognized at the point in time that control of the product is transferred to the customer and collectability is reasonably assured. Other revenue consists of iodine royalty income, which are point in time sales, and salt water disposal income, which is recognized over time. A more detailed summary of the underlying contracts that give rise to revenue and the method of recognition is included below.

Natural Gas and NGLs Sales

Under our gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity processes the natural gas, sells the resulting NGLs and residue gas to third parties and pays us for the NGLs and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction. For those contracts in which we concluded that we were the principal, the ultimate third party is the customer, and we recognize revenue on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense. Alternatively, for those contracts in which we concluded we were the agent, the purchaser is our customer, and we recognize revenue based on the net amount of the proceeds received from the purchaser.

Oil Sales

Under our oil sales contracts, we deliver all or a specified percentage of the crude oil production from specified leases to the purchaser at the wellhead. We sell oil production at the wellhead and collect an agreed-upon index price, net of applicable transport costs. We recognize revenue when control transfers to the purchaser at the wellhead at the net price received.

Other Revenue

Other revenue consists of fees charged to outside working interest owners for salt water disposal as well as royalties received from a third-party for iodine extracted from our salt water. Salt water disposal revenue is recognized over time because the customer simultaneously receives and consumes the benefit of the salt water disposal service as the service is provided. For salt water disposal income we utilized the practical expedient in ASC 606-10-55-18 that states that if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date, the entity may recognize revenue in the amount to which the entity has a right to invoice. Iodine royalty revenue is recognized point in time when control transfers to the customer.

Imbalances

We recognize revenue for all oil, NGLs and natural gas sold to purchasers regardless of whether the sales are proportionate to our ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds our share of remaining proved oil and gas reserves. We had no significant imbalances at June 30, 2018 or December 31, 2017.

Principal versus agent

We engage in various types of transactions in which midstream entities process our wet gas and, in some scenarios, subsequently market resulting NGLs and residue gas to third-party customers on our behalf, such as its percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. We analyzed control under ASC 606 and determined for those contracts where control passes at the wellhead, we act as agent and revenue should recognized net of amounts paid after such control passed for costs such as gathering, compression, processing and transportation, among others. The determination of control and the presentation of revenues was completed for ASC 606 purposes only. Amounts paid for royalties are calculated under a different methodology and may differ from the amount of revenues recognized under ASC 606.

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 Form 10-K for the year ended December 31, 2017. 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 interim condensed consolidated financial statements.

Recent Accounting Pronouncements Adopted During the Period

In March 2018, the FASB issued ASU 2018-05, "Income Taxes (Topic 740), Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118". ASU 2018-05 amends certain SEC paragraphs pursuant to the issuance of the December 2017 SEC SAB 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act*, which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act's enactment date for companies to complete its accounting under FASB ASC 740. In accordance with SAB 118, to the extent a company has not completed its analysis of the Tax Act but can provide a reasonable estimate, it must record a provisional estimate in its financial statements. We have accounted for certain tax effects of the Tax Act under the guidance of SAB 118, on a provisional basis. Our accounting for certain income tax effects is incomplete due to forthcoming guidance and the ongoing analysis of final year-end data and tax positions. We expect to complete our analysis within the measurement period in accordance with SAB 118.

In May 2014, the FASB issued ASU 2014-09, *"Revenue from Contracts with Customers (Topic 606)*". 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.

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We adopted ASU 2014-09 using the modified retrospective approach. The adoption of this guidance did not have a material impact on our financial statements. See Note 3 to the financial statements included in "Part I. Financial Information — Item 1. Financial Statements" of this report for further details.

Recent Accounting Pronouncements Issued But Not Yet Adopted

In June 2018, the FASB issued ASU 2018-07, "*Compensation - Stock Compensation (Topic 718) — Improvements to Nonemployee Share-Based Payment Accounting*". ASU 2018-07 expands the scope of Topic 718 to include share-based payments issued to nonemployees for goods and services. Consequently, the accounting for share-based payments to nonemployees and employees with be substantially aligned. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. We do not believe the adoption of ASU 2018-07 will have a material impact on our financial position, results of operations or cash flows.

In July 2017, the FASB issued ASU 2017-11, *"Earnings Per Share (Topic 260), Distinguishing Liabilities from Equity (Topic 480), and Derivatives and Hedging (Topic 815)"*. 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 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 our financial position, results of operations or cash flows.

In February 2016, the FASB issued ASU 2016-02, *"Leases (Topic 842)"*. ASU 2016-02 establishes a 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. When measuring lease assets and liabilities, payments to be made in optional extension periods should be included if the lessee is reasonably certain to exercise the option. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement.

For finance leases, we will recognize a ROU asset and liability, initially measured at the present value of the lease payments. Interest expense will be recognized on the lease liability separately from the amortization of the ROU asset. We will recognize payments of principal on the lease liability within financing activities in the consolidated statement of cash flows and payments of interest within operating activities in the consolidated statement of cash flows. For operating leases, we will recognize a ROU asset and liability, initially measured at the present value of the lease payments. We will recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis and all cash payments will be recognized in operating activities within the consolidated statement of cash flows.

In January 2018, the FASB issued ASU 2018-01, "*Leases (Topic 842)-Land Easement Practical Expedient for Transition to Topic 842*". ASU 2018-01 permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expired prior to a company's adoption of ASU 2016-02 and that were not accounted for as leases under previous lease guidance. 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 currently analyzing contracts to determine if they meet the definition of a lease under ASU 2016-02. We cannot reasonably quantify the impact of adoption at this time and expect to complete the assessment of ASU 2016-02 during the fourth quarter of 2018.

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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 Interim Condensed Consolidated Financial Statements — Note 5. 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. At June 30, 2018, we utilized fixed price swaps and three way collars to reduce the volatility of oil and natural gas prices on a portion of our future expected 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 June 30, 2018, a 10% change in the forward curves associated with our commodity derivative instruments would have changed our net liability positions by the following amounts:

	10% Increase	10% Decrease
	(in thousands)	
Gain (loss):		
Gas derivatives	$ (2,462)	$ 2,653
Oil derivatives	$ (12,721)	$ 11,832

Interest Rate Risk

At June 30, 2018, we had indebtedness outstanding under our RBL of $28.1 million, which bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. Assuming the RBL is fully drawn, a one percent increase in interest rates for the three months ended June 30, 2018, would have resulted in a $1.7 million increase in annual interest cost, before capitalization.

At June 30, 2018, 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 are 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, Chief Executive Officer and Director and our Vice President and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosures. Based on that evaluation, our President, Chief Executive Officer and Director and our Vice President and Chief Accounting Officer concluded that as of June 30, 2018, 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 June 30, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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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 Interim 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.

There have been no material changes to the risks described in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017, filed with the SEC on March 14, 2018.

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

The following table provides information regarding the purchase of our common stock made during the second quarter of 2018. Shares purchased represent the net settlement on vesting of restricted stock necessary to satisfy the minimum statutory withholding requirements.

Period	Total Number of Shares Purchased	Average Price Paid Per Share
April 1, 2018 — April 30, 2018	432	$ 13.88
May 1, 2018 — May 31, 2018	346	$ 14.15
June 1, 2018 — June 30, 2018	—	$ —
Total	778	$ 14.00

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.

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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).
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: August 6, 2018

/s/ DAVID J. SAMBROOKS
David J. Sambrooks
President, Chief Executive Officer and Director
(Principal Executive Officer)

Dated: August 6, 2018

/s/ RICHARD W. MCCULLOUGH
Richard W. McCullough
Vice President and Chief Accounting Officer
(Principal Financial Officer and Principal Accounting Officer)

EXHIBIT 31.1

CERTIFICATION

I, David J. Sambrooks, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q ("the report") for the quarterly period ended June 30, 2018, of Midstates Petroleum Company, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: August 6, 2018

/s/ DAVID J. SAMBROOKS
David J. Sambrooks
President, Chief Executive Officer and Director

EXHIBIT 31.2

CERTIFICATION

I, Richard W. McCullough, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q ("the report") for the quarterly period ended June 30, 2018, of Midstates Petroleum Company, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15(d)-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: August 6, 2018

/s/ RICHARD W. MCCULLOUGH
Richard W. McCullough
Vice President and Chief Accounting Officer

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, David J. Sambrooks, President, Chief Executive Officer and Director of Midstates Petroleum Company, Inc. (the "***Company***"), and Richard W. McCullough, Vice President and Chief Accounting Officer of the Company, certify that, to their knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the period ending June 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "***Report***"), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

MIDSTATES PETROLEUM COMPANY, INC.

Dated: August 6, 2018	/s/ DAVID J. SAMBROOKS David J. Sambrooks President, Chief Executive Officer and Director
Dated: August 6, 2018	/s/ RICHARD W. MCCULLOUGH Richard W. McCullough Vice President and Chief Accounting Officer