

Midstates Petroleum Company, Inc.  
Form 10-Q  
May 10, 2018  
[Table of Contents](#)

**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 March 31, 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)

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

**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, 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   
Non-accelerated filer   
(Do not check if a smaller reporting company)

Accelerated filer   
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 May 7, 2018 is shown below:

**Class**  
Common stock, \$0.01 par value

**Number of shares outstanding**  
25,256,957

**DOCUMENTS INCORPORATED BY REFERENCE**

None.

---

Table of Contents

**MIDSTATES PETROLEUM COMPANY, INC.**

**QUARTERLY REPORT ON**

**FORM 10-Q**

**FOR THE THREE MONTHS ENDED MARCH 31, 2018**

**TABLE OF CONTENTS**

	<b>Page</b>
<u>Glossary of Oil and Natural Gas Terms</u>	3
<b><u>PART I FINANCIAL INFORMATION</u></b>	
Item 1. Financial Statements	
<u>Condensed Consolidated Balance Sheets at March 31, 2018 and December 31, 2017 (unaudited)</u>	4
<u>Condensed Consolidated Statements of Operations for the Three Months Ended March 31, 2018 and 2017 (unaudited)</u>	5
<u>Condensed Consolidated Statements of Changes in Stockholders' Equity for the Three Months Ended March 31, 2018 and 2017 (unaudited)</u>	6
<u>Condensed Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2018 and 2017 (unaudited)</u>	7
<u>Notes to the Unaudited Condensed Consolidated Financial Statements</u>	8
<u>Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	24
<u>Item 3. Quantitative and Qualitative Disclosures About Market Risk</u>	37
<u>Item 4. Controls and Procedures</u>	38
<b><u>PART II OTHER INFORMATION</u></b>	
<u>Item 1. Legal Proceedings</u>	39
<u>Item 1A. Risk Factors</u>	39
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	39
<u>Item 3. Defaults upon Senior Securities</u>	39
<u>Item 4. Mine Safety Disclosures</u>	39
<u>Item 5. Other Information</u>	39
<u>Item 6. Exhibits</u>	39

EXHIBIT INDEX

40

SIGNATURES

41

Table of Contents

**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.



Table of Contents**PART I FINANCIAL INFORMATION****MIDSTATES PETROLEUM COMPANY, INC.****CONDENSED CONSOLIDATED BALANCE SHEETS****(Unaudited)****(In thousands, except share amounts)**

	March 31, 2018	December 31, 2017
<b>ASSETS</b>		
<b>CURRENT ASSETS:</b>		
Cash and cash equivalents	\$ 8,428	\$ 68,498
Accounts receivable:		
Oil and gas sales	30,467	32,455
Joint interest billing	3,691	3,297
Other	259	166
Commodity derivative contracts		762
Other current assets	3,124	1,510
Total current assets	45,969	106,688
<b>PROPERTY AND EQUIPMENT:</b>		
Oil and gas properties, on the basis of full-cost accounting		
Proved properties	798,593	765,308
Unproved properties not being amortized	7,142	7,065
Other property and equipment	6,502	6,508
Less accumulated depreciation, depletion, amortization and impairment	(219,590)	(204,419)
Net property and equipment	592,647	574,462
OTHER NONCURRENT ASSETS	7,006	6,978
<b>TOTAL</b>	<b>\$ 645,622</b>	<b>\$ 688,128</b>
<b>LIABILITIES AND EQUITY</b>		
<b>CURRENT LIABILITIES:</b>		
Accounts payable	\$ 6,652	\$ 11,547
Accrued liabilities	45,533	42,842
Commodity derivative contracts	6,062	3,433
Total current liabilities	58,247	57,822
<b>LONG-TERM LIABILITIES:</b>		
Asset retirement obligations	15,853	15,506
Commodity derivative contracts	950	562
Long-term debt	78,059	128,059
Other long-term liabilities	585	592
Total long-term liabilities	95,447	144,719
<b>COMMITMENTS AND CONTINGENCIES (Note 14)</b>		
<b>STOCKHOLDERS EQUITY:</b>		
Preferred stock, \$0.01 par value, 50,000,000 shares authorized; no shares issued or outstanding at March 31, 2018 and December 31, 2017		
Warrants, 6,625,554 warrants outstanding at March 31, 2018 and December 31, 2017	37,329	37,329
Common stock, \$0.01 par value, 250,000,000 shares authorized; 25,383,854 shares issued and 25,255,485 shares outstanding at March 31, 2018; 25,272,969 shares issued and 25,173,346 shares outstanding at December 31, 2017	254	253
Treasury stock	(2,062)	(1,603)

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

Additional paid-in-capital	527,550	524,755
Retained deficit	(71,143)	(75,147)
Total stockholders' equity	491,928	485,587
<b>TOTAL</b>	<b>\$ 645,622</b>	<b>\$ 688,128</b>

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

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

	<b>For the Three Months Ended March 31,</b>	
	<b>2018</b>	<b>2017</b>
<b>REVENUES:</b>		
Oil sales	\$ 32,414	\$ 31,036
Natural gas liquid sales	11,038	11,194
Natural gas sales	8,337	17,098
Other revenue	1,055	822
Total revenue from contracts with customers	52,844	60,150
Gains (losses) on commodity derivative contracts net	(3,939)	4,865
Total revenues	48,905	65,015
<b>EXPENSES:</b>		
Lease operating and workover	14,808	15,852
Gathering and transportation (Note 3)	57	3,687
Severance and other taxes	2,861	2,121
Asset retirement accretion	297	276
Depreciation, depletion, and amortization	15,213	15,342
General and administrative	9,857	8,275
Total expenses	43,093	45,553
<b>OPERATING INCOME</b>	<b>5,812</b>	<b>19,462</b>
<b>OTHER EXPENSE:</b>		
Interest income	19	
Interest expense net of amounts capitalized	(1,827)	(977)
Total other expense	(1,808)	(977)
<b>INCOME BEFORE TAXES</b>	<b>4,004</b>	<b>18,485</b>
Income tax expense		
<b>NET INCOME</b>	<b>\$ 4,004</b>	<b>\$ 18,485</b>
Participating securities non-vested restricted stock	(99)	(546)
<b>NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS</b>	<b>\$ 3,905</b>	<b>\$ 17,939</b>
Basic and diluted net income per share attributable to common shareholders	\$ 0.15	\$ 0.72
Basic and diluted weighted average number of common shares outstanding (Note 12)	25,299	25,012

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

Table of Contents

## 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
<b>Balance as of December 31, 2017</b>	\$	\$ 253	\$ 37,329	\$ (1,603)	\$ 524,755	\$ (75,147)	\$ 485,587
Share-based compensation		1			2,795		2,796
Acquisition of treasury stock				(459)			(459)
Net income						4,004	4,004
<b>Balance as of March 31, 2018</b>	\$	\$ 254	\$ 37,329	\$ (2,062)	\$ 527,550	\$ (71,143)	\$ 491,928

	Series A Preferred Stock	Common Stock	Warrants	Treasury Stock	Additional Paid-in-Capital	Retained Earnings	Total Stockholders Equity
<b>Balance as of December 31, 2016</b>	\$	\$ 250	\$ 37,329	\$	\$ 514,305	\$ 9,930	\$ 561,814
Share-based compensation					3,790		3,790
Acquisition of treasury stock							
Net income						18,485	18,485
<b>Balance as of March 31, 2017</b>	\$	\$ 250	\$ 37,329	\$	\$ 518,095	\$ 28,415	\$ 584,089

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

Table of Contents

## MIDSTATES PETROLEUM COMPANY, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	For the Three Months Ended March 31,	
	2018	2017
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>		
Net income	\$ 4,004	\$ 18,485
<i>Adjustments to reconcile net income to net cash provided by operating activities:</i>		
(Gains) losses on commodity derivative contracts net	3,939	(4,865)
Net cash received (paid) for commodity derivative contracts not designated as hedging instruments	(160)	811
Asset retirement accretion	297	276
Depreciation, depletion, and amortization	15,213	15,342
Share-based compensation, net of amounts capitalized to oil and gas properties	2,210	3,337
Amortization of deferred financing costs	108	80
<i>Change in operating assets and liabilities:</i>		
Accounts receivable oil and gas sales	1,293	2,812
Accounts receivable JIB and other	(663)	(842)
Other current and noncurrent assets	(1,750)	(656)
Accounts payable	(1,467)	1,279
Accrued liabilities	(869)	(3,649)
Other	(8)	(37)
<b>Net cash provided by operating activities</b>	<b>\$ 22,147</b>	<b>\$ 32,373</b>
<b>CASH FLOWS FROM INVESTING ACTIVITIES:</b>		
Investment in property and equipment	\$ (31,758)	\$ (26,108)
Proceeds from the sale of oil and gas equipment		1,350
<b>Net cash used in investing activities</b>	<b>\$ (31,758)</b>	<b>\$ (24,758)</b>
<b>CASH FLOWS FROM FINANCING ACTIVITIES:</b>		
Repayment of revolving credit facility	\$ (50,000)	\$
Repurchase of restricted stock for tax withholdings	(459)	
<b>Net cash used in financing activities</b>	<b>\$ (50,459)</b>	<b>\$</b>
<b>NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS</b>	<b>\$ (60,070)</b>	<b>\$ 7,615</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>\$ 68,498</b>	<b>\$ 76,838</b>
<b>Cash and cash equivalents, end of period</b>	<b>\$ 8,428</b>	<b>\$ 84,453</b>
<b>SUPPLEMENTAL INFORMATION:</b>		
Non-cash transactions investments in property and equipment accrued not paid	\$ 18,508	\$ 17,440
Cash paid for interest, net of capitalized interest of \$0.1 million and \$0.9 million, respectively	\$ 1,785	\$ 937

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



Table of Contents

**MIDSTATES PETROLEUM COMPANY, INC.**

**Notes to Unaudited Condensed Consolidated Financial Statements**

**1. Organization and Business**

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

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

**2. Summary of Significant Accounting Policies**

*Basis of Presentation*

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ( SEC ) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America ( US GAAP ) for complete consolidated financial statements, and should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 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 condensed consolidated financial statements include all adjustments, consisting of normal recurring adjustments, necessary to fairly present the financial position as of, and the results of operations for, all periods presented. In preparing the accompanying unaudited condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the unaudited condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

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 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 August 2016, the FASB issued Accounting Standards Update 2016-15, *Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments ( ASU 2016-15 )*. ASU 2016-15 addresses eight specific cash flow issues with the objective of reducing existing diversity of practice. The eight specific cash flow issues contained within ASU 2016-15 are debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. ASU 2016-15 is effective for the Company for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The adoption of ASU 2016-15 did not have a material impact on our statements of cash flows.



Table of Contents

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 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 in the initial evaluation stage for ASU 2016-02 and related interpretations and guidance. 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.



Table of Contents**3. Impact of ASC 606 Adoption**

On January 1, 2018, the Company adopted ASC 606, *Revenue from Contracts with Customers* ( ASC 606 ) using the modified retrospective method of transition. ASC 606 supersedes previous revenue recognition requirements in ASC 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 current period results is as follows (in thousands):

	Three Months Ended March 31, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
<b>Revenues :</b>			
Oil sales	\$ 32,414	\$ 32,424	\$ (10)
Natural gas liquid sales	11,038	11,065	(27)
Natural gas sales	8,337	11,400	(3,063)
Gathering and transportation	57	3,070	(3,013)
Lease operating and workover expense	14,808	14,895	(87)
<b>Net income</b>	<b>\$ 4,004</b>	<b>\$ 4,004</b>	<b>\$</b>
<b>Retained deficit</b>	<b>\$ (71,143)</b>	<b>\$ (71,143)</b>	<b>\$</b>

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

## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

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 collect 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.

Table of Contents

*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 March 31, 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.

## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

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.

### *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 months ended March 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Table of Contents**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 condensed consolidated balance sheets are recorded at estimated fair value. At March 31, 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 condensed consolidated statements of operations.

	Fair Value Measurements at March 31, 2018			Total
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
(in thousands)				
<b>Derivative Assets:</b>				
Commodity derivative oil swaps	\$	\$ 2	\$	\$ 2
Commodity derivative gas swaps	\$	\$ 74	\$	\$ 74
Commodity derivative oil collars	\$	\$ 4,764	\$	\$ 4,764
Commodity derivative gas collars	\$	\$ 1,415	\$	\$ 1,415
<b>Total assets</b>	<b>\$</b>	<b>\$ 6,255</b>	<b>\$</b>	<b>\$ 6,255</b>
<b>Derivative Liabilities:</b>				
Commodity derivative oil swaps	\$	\$ (4,293)	\$	\$ (4,293)
Commodity derivative gas swaps	\$	\$ (205)	\$	\$ (205)
Commodity derivative oil collars	\$	\$ (8,208)	\$	\$ (8,208)
Commodity derivative gas collars	\$	\$ (561)	\$	\$ (561)
<b>Total liabilities</b>	<b>\$</b>	<b>\$ (13,267)</b>	<b>\$</b>	<b>\$ (13,267)</b>

	Fair Value Measurements at December 31, 2017			Total
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
(in thousands)				
<b>Derivative Assets:</b>				
Commodity derivative oil swaps	\$	\$	\$	\$
Commodity derivative gas swaps	\$	\$ 821	\$	\$ 821

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

Commodity derivative oil collars	\$	\$	952	\$	\$	952
Commodity derivative gas collars	\$	\$	2,611	\$	\$	2,611
<b>Total assets</b>	<b>\$</b>	<b>\$</b>	<b>4,384</b>	<b>\$</b>	<b>\$</b>	<b>4,384</b>
<b>Derivative Liabilities:</b>						
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)
<b>Total liabilities</b>	<b>\$</b>	<b>\$</b>	<b>(7,617)</b>	<b>\$</b>	<b>\$</b>	<b>(7,617)</b>



Table of Contents

**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 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 March 31, 2018, the Company would not have experienced a loss.

***Commodity Derivative Contracts***

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

## NYMEX WTI

Quarter Ended:	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
March 31, 2018(1)	99,000	\$ 50.61	225,000	\$ 62.14	\$ 50.00	\$ 40.00
June 30, 2018(1)	154,750	\$ 51.97	182,000	\$ 60.65	\$ 50.00	\$ 40.00
September 30, 2018(1)	151,800	\$ 55.23	184,000	\$ 59.93	\$ 50.00	\$ 40.00
December 31, 2018(1)	289,800	\$ 57.79	46,000	\$ 56.70	\$ 50.00	\$ 40.00
March 31, 2019(1)		\$	180,000	\$ 63.14	\$ 53.75	\$ 43.75
June 30, 2019(1)		\$	182,000	\$ 63.14	\$ 53.75	\$ 43.75
September 30, 2019(1)		\$	184,000	\$ 63.14	\$ 53.75	\$ 43.75
December 31, 2019(1)		\$	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

Table of Contents

	Fixed Swaps		NYMEX HENRY HUB				
	Hedge Position (MMBtu)	Weighted Avg Strike Price	Hedge Position (MMBtu)	Weighted Avg Ceiling Price	Three-Way Collars Weighted Avg Floor Price	Weighted Avg Sub-Floor Price	
<b>Quarter Ended:</b>							
March 31, 2018(1)(2)	1,350,000	\$ 3.47	1,530,000	\$ 4.38	\$ 3.25	\$ 2.50	
June 30, 2018(1)	915,000	\$ 2.79	1,365,000	\$ 3.40	\$ 3.00	\$ 2.50	
September 30, 2018(1)	1,380,000	\$ 2.79	1,380,000	\$ 3.40	\$ 3.00	\$ 2.50	
December 31, 2018(1)	1,380,000	\$ 2.91	1,380,000	\$ 3.40	\$ 3.00	\$ 2.50	
March 31, 2019(1)	1,350,000	\$ 2.98	1,350,000	\$ 3.40	\$ 3.00	\$ 2.50	

(1) Positions shown represent open commodity derivative contract positions as of March 31, 2018.

(2) During the second quarter of 2017, the Company entered into natural gas three-way collars with long call ceilings in order to offset its Q1 2018 natural gas fixed swaps.

**Balance Sheet Presentation**

The following table summarizes the net fair values of commodity derivative instruments by the appropriate balance sheet classification in the Company's unaudited condensed consolidated balance sheets for the periods presented (in thousands):

Type	Balance Sheet Location (1)	March 31, 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
<b>Total derivative financial instruments</b>	<b>current assets</b>	\$	\$ <b>762</b>
Oil swaps	Derivative financial instruments current liabilities	\$ (4,291)	\$ (3,679)
Gas swaps	Derivative financial instruments current liabilities	(131)	
Oil collars	Derivative financial instruments current liabilities	(2,494)	(370)
Gas collars	Derivative financial instruments current liabilities	854	616
<b>Total derivative financial instruments</b>	<b>current liabilities</b>	\$ <b>(6,062)</b>	\$ <b>(3,433)</b>
Oil collars	Derivative financial instruments noncurrent liabilities	\$ (950)	\$ (523)
Gas collars	Derivative financial instruments noncurrent liabilities		(39)
<b>Total derivative financial instruments</b>	<b>noncurrent liabilities</b>	\$ <b>(950)</b>	\$ <b>(562)</b>
<b>Total derivative fair value at period end</b>		\$ <b>(7,012)</b>	\$ <b>(3,233)</b>

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

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

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

Not Designated as ASC 815 Hedges	Balance Sheet Location Classification			Gross Recognized Assets/Liabilities	March 31, 2018		Net Recognized Fair Value Assets/Liabilities
					Gross Amounts Offset		
<b>Derivative Assets:</b>							
Commodity contracts	Derivative financial instruments	current	\$	2,134	\$	(2,134)	\$
Commodity contracts	Derivative financial instruments	noncurrent		4,121		(4,121)	
			\$	<b>6,255</b>	\$	<b>(6,255)</b>	\$
<b>Derivative Liabilities:</b>							
Commodity contracts	Derivative financial instruments	current	\$	(8,196)	\$	2,134	\$ (6,062)
Commodity contracts	Derivative financial instruments	noncurrent		(5,071)		4,121	(950)
			\$	<b>(13,267)</b>	\$	<b>6,255</b>	\$ <b>(7,012)</b>

Table of Contents

Not Designated as ASC 815 Hedges	Balance Sheet Location	Classification	Gross Recognized Assets/Liabilities	December 31, 2017		Net Recognized Fair Value Assets/Liabilities
				Gross Amounts	Offset	
<b>Derivative Assets:</b>						
Commodity contracts	Derivative financial instruments	current	\$ 3,479	\$ (2,717)		\$ 762
Commodity contracts	Derivative financial instruments	noncurrent	905	(905)		
			<b>\$ 4,384</b>	<b>\$ (3,622)</b>		<b>\$ 762</b>
<b>Derivative Liabilities:</b>						
Commodity contracts	Derivative financial instruments	current	\$ (6,150)	\$ 2,717		\$ (3,433)
Commodity contracts	Derivative financial instruments	noncurrent	(1,467)	905		(562)
			<b>\$ (7,617)</b>	<b>\$ 3,622</b>		<b>\$ (3,995)</b>

*Gains/Losses on Commodity Derivative Contracts*

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

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

	For the Three Months Ended March 31,	
	2018	2017
Net cash received (paid) for commodity derivative contracts	\$ (160)	\$ 811
Unrealized net gains (losses)	(3,779)	4,054
<b>Gains (losses) on commodity derivative contracts net</b>	<b>\$ (3,939)</b>	<b>\$ 4,865</b>

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

**6. Property and Equipment**

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

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

	March 31, 2018	December 31, 2017
	(in thousands)	
Oil and gas properties, on the basis of full-cost accounting:		
Proved properties	\$ 798,593	\$ 765,308
Unproved properties not being amortized	7,142	7,065
Other property and equipment	6,502	6,508
Less accumulated depreciation, depletion, amortization and impairment	(219,590)	(204,419)
<b>Net property and equipment</b>	<b>\$ 592,647</b>	<b>\$ 574,462</b>

Table of Contents

*Oil and Gas Properties*

The Company capitalizes internal costs directly related to exploration and development activities to oil and gas properties. During the three months ended March 31, 2018 and 2017, the Company capitalized the following (in thousands):

	2018	2017
Internal costs capitalized to oil and gas properties (1)	\$ 895	\$ 3,017

(1) Inclusive of \$0.2 million and \$0.7 million of qualifying share-based compensation expense for the three months ended March 31, 2018 and 2017, respectively.

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 three months ended March 31, 2018, the Company signed a purchase and sale agreement for its Anadarko Basin assets for \$58.0 million before customary closing or post-closing adjustments. The sale of the Anadarko Basin assets will not result in a significant alteration of the full cost pool and therefore, no gain or loss will be recognized when the transaction closes. During the three months ended March 31, 2017, the Company disposed of certain oil and gas equipment for cash proceeds of \$1.4 million, which were reflected as reduction of oil and gas properties with no gain or loss recognized.

The Company performs a full-cost ceiling test on a quarterly basis. The test establishes a limit (ceiling) on the book value of the Company's oil and gas properties. The capitalized costs of oil and gas properties, net of accumulated depreciation, depletion, amortization and impairment (DD&A) and the related deferred income taxes, may not exceed this ceiling. The ceiling limitation is equal to the sum of: (i) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet, calculated using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged to expense in the accompanying unaudited condensed consolidated statements of operations. The Company did not record an impairment of oil and gas properties during the three months ended March 31, 2018 or 2017.

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  
March 31,**

**Three Months Ended  
March 31,**

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

	2018		2017		2018		2017	
	(in thousands)				(per Boe)			
Depletion expense	\$	14,623	\$	14,753	\$	8.45	\$	6.96
Depreciation on other property and equipment		590		589		0.34		0.28
<b>Depreciation, depletion, and amortization</b>	<b>\$</b>	<b>15,213</b>	<b>\$</b>	<b>15,342</b>	<b>\$</b>	<b>8.79</b>	<b>\$</b>	<b>7.24</b>

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 months ended March 31, 2018 or 2017. Unproved property was \$7.1 million at March 31, 2018 and December 31, 2017, respectively.



Table of Contents**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.

**7. Accrued Liabilities**

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

	March 31, 2018	December 31, 2017	
	(in thousands)		
Accrued oil and gas capital expenditures	\$ 13,853	\$	9,081
Accrued revenue and royalty distributions	17,195		18,701
Accrued lease operating and workover expense	5,340		5,150
Accrued interest	42		108
Accrued taxes	2,483		2,758
Compensation and benefit related accruals	2,351		4,520
Other	4,269		2,524
<b>Accrued liabilities</b>	<b>\$ 45,533</b>	<b>\$</b>	<b>42,842</b>

**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):

		Three Months Ended		
		March 31,		
		2018		2017
Asset retirement obligations	beginning of period	\$ 15,506	\$	14,200
Liabilities incurred		113		90
Revisions				
Liabilities settled		(1)		(30)
Liabilities eliminated through asset sales		(62)		
Current period accretion expense		297		276
<b>Asset retirement obligations</b>	<b>end of period</b>	<b>\$ 15,853</b>	<b>\$</b>	<b>14,536</b>

**9. Debt**

***Reserves-Based Revolving Credit Facility ( RBL )***

At March 31, 2018 and December 31, 2017, the Company maintained an RBL with a borrowing base of \$170.0 million. During the three months ended March 31, 2018, the Company paid down \$50.0 million on its RBL. At March 31, 2018 and December 31, 2017, the Company had \$78.1 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 March 31, 2018, the Company had \$90.0 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 March 31, 2018, the weighted average interest rate, including amortization expense of deferred financing costs, was 6.9%. Unamortized debt issuance costs of \$1.1 million and \$1.2 million associated with the RBL are included in other noncurrent assets on the unaudited condensed consolidated balance sheets at March 31, 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.

Table of Contents

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 March 31, 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.

The Company believes the carrying amount of the RBL at March 31, 2018 approximates its fair value (Level 2) due to the variable nature of the RBL interest rate.

**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 three months ended March 31, 2018:

	Common Stock	Treasury Stock(1)
<b>Share count as of December 31, 2017</b>	<b>25,272,969</b>	<b>(99,623)</b>
Common stock issued	110,885	
Acquisition of treasury stock		(28,746)
<b>Share count as of March 31, 2018</b>	<b>25,383,854</b>	<b>(128,369)</b>

(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 Effective Date), the Company established the 2016 LTIP and filed a Form S-8 with the SEC, registering 3,513,950 shares for issuance under the terms of the 2016 LTIP to employees, directors and certain other persons (the Award Shares). The types of awards that may be granted under the 2016 LTIP include stock options, restricted stock units, restricted stock, performance awards and other forms of awards granted or denominated in shares of common stock of the reorganized Company, as well as certain cash-based awards (the Awards). The terms of each award are as determined by the Compensation Committee of the Board of Directors. Awards that expire, or are canceled, forfeited, exchanged, settled in cash or otherwise terminated, will again be available for future issuance under the 2016 LTIP. At March 31, 2018, 1,763,238 Award Shares remain available for issuance under the terms of the 2016 LTIP.

*Restricted Stock Units*

At March 31, 2018, the Company had 491,693 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 three months ended March 31, 2018, 269,468 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.

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

Table of Contents

The following table summarizes the Company's non-vested restricted stock unit award activity for the three months ended March 31, 2018:

	Restricted Stock	Weighted Average Grant Date Fair Value
<b>Non-vested shares outstanding at December 31, 2017</b>	<b>324,984</b>	<b>\$ 18.84</b>
Granted	269,468	\$ 14.25
Vested(1)	(102,759)	\$ 19.66
Forfeited		\$
<b>Non-vested shares outstanding at March 31, 2018</b>	<b>491,693</b>	<b>\$ 16.16</b>

(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 three months ended March 31, 2018.

Unrecognized expense as of March 31, 2018 for all outstanding restricted stock units under the 2016 LTIP Plan was \$5.5 million and will be recognized over a weighted average period of 1.4 years.

*Stock Options*

At March 31, 2018, the Company had 143,086 non-vested options outstanding pursuant to the 2016 LTIP. Stock Option Awards granted under the 2016 LTIP vest ratably over a period of three years: one-sixth will vest on the six-month anniversary of the grant date, an additional one-sixth will vest on the twelve-month anniversary of the grant date, an additional one-third will vest on the twenty-four month anniversary of the grant date and the final one-third will vest on the thirty-six month anniversary of the grant date. Stock Option Awards expire 10 years from the grant date. There were no issuances of stock options during the three months ended March 31, 2018.

The following table summarizes the Company's 2016 LTIP non-vested stock option activity for the three months ended March 31, 2018:

	Options	Range of Exercise Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)
<b>Stock options outstanding at December 31, 2017</b>	<b>245,845</b>		<b>\$ 19.66</b>	<b>8.6</b>
Granted		\$	\$	
Vested(1)	(102,759)	\$ 19.08-19.66	\$ 19.66	0.4
Forfeited		\$	\$	
<b>Stock options outstanding at March 31, 2018</b>	<b>143,086</b>		<b>\$ 19.66</b>	<b>8.6</b>
<b>Vested and exercisable at end of period(2)</b>	<b>356,437</b>	<b>\$ 19.08-20.97</b>	<b>\$ 19.66</b>	<b>6.7</b>

(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 three months ended March 31, 2018.

(2) Vested and exercisable options at March 31, 2018, had no aggregate intrinsic value.

Unrecognized expense as of March 31, 2018 for all outstanding stock options under the 2016 LTIP Plan was \$0.6 million and will be recognized over a weighted average period of 1.1 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).

Table of Contents

These restricted stock awards are accounted for as liability awards under FASB ASC 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 March 31, 2018 the Company recorded a \$0.5 million liability included within accrued liabilities on the unaudited condensed consolidated balance sheets related to the market condition awards. The weighted-average fair value of the restricted stock units containing a market condition was \$6.90 at March 31, 2018.

As of March 31, 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 (1) 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 (2) 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 at March 31, 2018. As of March 31, 2018, unrecognized stock-based compensation related to CEO RSUs containing a market condition was \$1.3 million and will be recognized over a weighted-average period of 2.6 years.

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

## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

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. Market conditions under this grant relate to the Company's Relative TSR as follows:

	<b>Relative TSR for the Performance Period</b>	<b>Vesting as % of RSUs Granted</b>
Maximum	Top 35% or better Relative TSR to Peer Group	150%
Target	Top 50% or better Relative TSR to Peer Group	100%
Threshold	Top 60% or better Relative TSR to Peer Group	50%
Below Threshold	Less than 60% of Relative TSR to Peer Group	0%

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%.



## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

### Table of Contents

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 (1) accelerate all or a portion of the award, (2) cancel all of the award and pay cash, stock or combination equal to the change in control price, (3) provide for the assumption or substitution or continuation by the successor company, (4) certify to the extent to which the vesting conditions had been achieved prior to the conclusion of the performance period or (5) 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.

A Monte Carlo simulation was used in order to determine the fair value of these awards at the grant date. The assumptions used to estimate the fair value of the executive management restricted stock unit awards with a market condition are as follows:

	<b>Awards Issued March 1, 2018</b>
Risk-free interest rate (1)	2.34%
Dividend yield	
Expected volatility	40.0% - 127.2%
Calculated fair value per unit	\$13.34

(1) U.S. Treasury yields as of the grant date were utilized for the risk-free interest rate assumption, matching the treasury yield terms to the life of the executives restricted stock unit award with a market condition.

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 for the period ended March 31, 2018. As of March 31, 2018, unrecognized stock-based compensation related to executive management's restricted stock units containing a market condition was \$1.2 million and will be recognized over a weighted-average period of 2.8 years.

The following table reflects the outstanding Executive Management restricted stock units containing a market condition for the three months ended March 31, 2018:

	Shares		Weighted Average Fair Value
<b>Outstanding at December 31, 2017</b>		\$	
Granted	96,305	\$	13.34

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

Vested		\$	
Forfeited		\$	
<b>Outstanding at March 31, 2018</b>	96,305	\$	13.34

**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 9-12 months. Therefore, for the three months ended March 31, 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.

Table of Contents

For the three months ended March 31, 2018, the Company has estimated deductions of \$9.0 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 March 31, 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 three months ended March 31, 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 three months ended March 31, 2018, the Company's valuation allowance decreased by \$1.1 million from December 31, 2017, bringing the total valuation allowance to \$119.0 million at March 31, 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:

	<b>Three Months Ended March 31,</b>	
	<b>2018</b>	<b>2017</b>
	<b>(in thousands, except per share amounts)</b>	
<b>Net Income:</b>		
Net income	\$ 4,004	\$ 18,485
Participating securities non-vested restricted stock	(99)	(546)
<b>Basic and diluted income</b>	<b>\$ 3,905</b>	<b>\$ 17,939</b>
<b>Common Shares:</b>		
<b>Common shares outstanding basic (1)</b>	<b>25,299</b>	<b>25,012</b>
Dilutive effect of potential common shares		
<b>Common shares outstanding diluted</b>	<b>25,299</b>	<b>25,012</b>
<b>Net Income Per Share:</b>		
Basic	\$ 0.15	\$ 0.72
Diluted	\$ 0.15	\$ 0.72
Antidilutive stock options (2)	500	627
Antidilutive warrants (3)	6,626	6,626

(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 March 31, 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 (the Plan ) 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 earnings 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.

Table of Contents

**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 condensed consolidated balance sheets at December 31, 2017 to EcoStim that was paid during the three months ended March 31, 2018. No transactions with EcoStim occurred during the three months ended March 31, 2017.

**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 March 31, 2018 and December 31, 2017, the Company s total accrual for all loss contingencies was \$1.1 million.

Table of Contents

**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 condensed consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q.*

**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 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;

Table of Contents

- 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 primarily focused on exploration and production activities in the Mississippian Lime and Anadarko Basin. The terms Company, we, us, our, and similar terms refer to us and our subsidiary, unless the context indicates otherwise.

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

**Recent Developments**

*Disposition of Anadarko Basin Assets*

On March 29, 2018, we entered into a purchase and sale agreement with an undisclosed buyer pursuant to which we agreed to sell substantially all of our wells and the leases related thereto located in the Anadarko Basin in Texas and Oklahoma for a contract price of \$58.0 million, subject to customary closing and post-closing adjustments. This divestiture is expected to close on or around May 30, 2018, with an effective date of January 1, 2018.



***Partial Pay-Down of RBL***

During March 2018, we paid down approximately \$50.0 million of our outstanding RBL balance using available cash on hand.

**Operations Update*****Mississippian Lime***

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

	<b>Three Months Ended March 31, 2018</b>	<b>Three Months Ended December 31, 2017</b>	<b>Decrease in Production</b>
<b>Average daily production:</b>			
Oil (Bbls)	4,564	4,960	(8.0)%
Natural gas liquids (Bbls)	3,644	3,903	(6.6)%
Natural gas (Mcf)	43,857	50,787	(13.6)%
<b>Net Boe/day</b>	<b>15,518</b>	<b>17,327</b>	<b>(10.4)%</b>

Table of Contents

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

	Total Number of Gross Horizontal Wells Spud (1)	Total Number of Gross Horizontal Wells Brought into Production
Mississippian Lime	4	6

(1) We had one rig drilling in the Mississippian Lime horizontal well program at March 31, 2018. Of the four wells spud, none were producing, three were awaiting completion and one was being drilled at quarter-end. In addition, five wells spud in 2017 were awaiting completion at March 31, 2018.

In the first quarter of 2018, we incurred approximately \$32.2 million of operational capital expenditures in the Mississippian Lime basin.

*Anadarko Basin*

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

	Three Months Ended March 31, 2018	Three Months Ended December 31, 2017	Decrease in Production
<b>Average daily production:</b>			
Oil (Bbls)	1,207	1,347	(10.4)%
Natural gas liquids (Bbls)	1,065	1,065	0.0%
Natural gas (Mcf)	8,671	8,867	(2.2)%
<b>Net Boe/day</b>	<b>3,717</b>	<b>3,890</b>	<b>(4.4)%</b>

We did not spud any wells in our Anadarko Basin asset and did not have any operated drilling rigs in the area during the first quarter of 2018. As discussed above, we have entered into a purchase and sale agreement to divest of substantially all of our Anadarko Basin assets, which we expect to close on or around May 30, 2018.

*Capital Expenditures*

During the three months ended March 31, 2018, we incurred operational capital expenditures of \$32.2 million, which consisted of the following:

Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

Drilling and completion activities	\$	30,754
Acquisition of acreage and seismic data		1,437
<b>Operational capital expenditures incurred</b>	<b>\$</b>	<b>32,191</b>
Capitalized G&A, office, ARO & other		1,220
Capitalized interest		77
<b>Total capital expenditures incurred</b>	<b>\$</b>	<b>33,488</b>

Operational capital expenditures by area were as follows:

Mississippian Lime	\$	32,205
Anadarko Basin		(14)
<b>Total operational capital expenditures incurred</b>	<b>\$</b>	<b>32,191</b>

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 \$120.0 million in this area.

Table of Contents

**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. In the first quarter of 2018, the results of our full cost ceiling test did not require us to recognize an impairment of our oil and gas properties. While impairments do not impact cash flow from operating activities or liquidity, they do decrease our net income and shareholders' equity.

We dispose of large volumes of saltwater produced in conjunction with 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 into belowground disposal wells contribute to seismic activity in certain areas, including Oklahoma and Texas, where we operate. The Oil and Gas Conservation Division ( OGCD ) established caps for additional wells, including 16 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. 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 Oklahoma Corporation Commission ( 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.

Table of Contents**Results of Operations**

The following table summarizes our revenues for the periods indicated (in thousands):

	Crude Oil		NGLs		Natural Gas		Total
Revenues for the three months ended March 31, 2017	\$	31,036	\$	11,194	\$	17,098	\$ 59,328
Changes due to volumes		(5,349)		(1,914)		(3,380)	(10,643)
Changes due to price(1)		6,727		1,758		(5,381)	3,104
Revenues for the three months ended March 31, 2018	\$	32,414	\$	11,038	\$	8,337	\$ 51,789

(1) Changes due to price for natural gas includes \$3.0 million in gathering and transportation expense that as a result of ASC 606, being net against revenues in the unaudited condensed consolidated statements of operations. Oil, NGLs and natural gas included \$0.1 million, respectively, of lease operating expense that are now being netted against revenues in the unaudited 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 table sets forth information regarding average realized sales prices for the periods indicated (per BOE):

	Crude Oil		NGLs		Natural Gas	
	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Average sales price exclusive of realized derivatives and certain deductions from revenue	\$ 62.43	\$ 49.48	\$ 26.11	\$ 21.89	\$ 2.41	\$ 2.90
Realized derivatives	(2.84)	0.78			0.28	0.06
Average sales price with realized derivatives exclusive of certain deductions from revenue	\$ 59.59	\$ 50.26	\$ 26.11	\$ 21.89	\$ 2.69	\$ 2.96
Certain deductions from revenue (1)	(0.02)		(0.07)		(0.65)	
Average sales price inclusive of realized derivatives and certain deductions from revenue (1)	\$ 59.57		\$ 26.04		\$ 2.04	

---

(1) Average realized prices for the three months ended March 31, 2017 were based upon revenues as presented under ASC 605. As a result, the appropriate realized price for comparison purposes with March 31, 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.

Table of Contents*Oil, NGLs and Natural Gas Production*

	For the Three Months Ended March 31, 2018	For the Three Months Ended March 31, 2017	% Change
<b>PRODUCTION DATA:</b>			
Oil (Bbls/d)			
Mississippian Lime	4,564	5,605	(18.6)%
Anadarko Basin	1,207	1,364	(11.5)%
Natural gas liquids (Bbls/d)			
Mississippian Lime	3,644	4,588	(20.6)%
Anadarko Basin	1,065	1,093	(2.6)%
Natural gas (Mcf/d)			
Mississippian Lime	43,857	56,075	(21.8)%
Anadarko Basin	8,671	9,394	(7.7)%
Combined (Boe/d)			
Mississippian Lime	15,518	19,539	(20.6)%
Anadarko Basin	3,717	4,023	(7.6)%

*Oil Revenues*

Our oil sales revenue increased by \$1.4 million, or 4.4% to \$32.4 million during the three months ended March 31, 2018. Oil volumes sold decreased 1,198 Boe/day, or 17.2%, to 5,771 Boe/day for the three months ended March 31, 2018 primarily due to decreased production in the Mississippian Lime assets of 1,041 Boe/day as a result of reduced drilling activity and natural decline. Average oil sales prices, without realized derivatives and certain deductions, increased by \$12.95 per barrel, or 26.2%, largely as a result of a significant increase in prevailing market prices.

*NGLs Revenues*

Our NGLs revenue decreased by \$0.2 million, or 1.4% to \$11.0 million during the three months ended March 31, 2018. NGLs volumes sold decreased 972 Boe/day, or 17.1%, to 4,709 Boe/day for the three months ended March 31, 2018, primarily due to decreased production in the Mississippian Lime assets of 944 Boe/day as a result of reduced drilling activity and natural decline. Average NGLs sales prices, without realized derivatives and certain deductions, increased by \$4.22 per barrel, or 19.3%, largely as a result of higher oil prices, which correlate with NGLs pricing.

*Natural Gas Revenues*

Our natural gas sales revenue decreased by \$8.8 million, or 51.2% to \$8.3 million during the three months ended March 31, 2018. Natural gas volumes sold decreased 12,941 Mcf/day, or 19.8%, to 52,528 Mcf/day for the three months ended March 31, 2018, primarily due to decreased production in the Mississippian Lime assets of 12,218 Mcf/day as a result of reduced drilling activity and natural decline. Average natural gas sales prices, without realized derivatives and gathering and transportation expenses, decreased by \$0.49 per Mcf, or 16.9%, to \$2.41 per Mcf



## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

largely due to lower prevailing index prices at our delivery points. Beginning January 1, 2018, we adopted ASC 606, and as a result, \$3.0 million in gathering and transportation expenses are now being netted against gas sales revenue in the unaudited 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.

Table of Contents***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):

	<b>For the Three Months Ended March 31, 2018</b>	<b>For the Three Months Ended March 31, 2017</b>
Cash receipts (payments) on settlement		
Oil derivatives	\$ (1,476)	\$ 489
Natural gas derivatives	1,316	322
<b>Total cash settlements</b>	<b>\$ (160)</b>	<b>\$ 811</b>
Gains (losses) due to fair value changes		
Oil derivatives	\$ (2,404)	\$ 3,231
Natural gas derivatives	(1,375)	823
<b>Total gains (losses) on fair value changes</b>	<b>\$ (3,779)</b>	<b>\$ 4,054</b>
<b>Gains (losses) on commodity derivative contracts net</b>	<b>\$ (3,939)</b>	<b>\$ 4,865</b>

Our mark-to-market ( MTM ) derivative positions moved to a \$3.8 million unrealized loss for the three months ended March 31, 2018, from a \$4.1 million unrealized gain for the three months ended March 31, 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***

	<b>Three Months Ended March 31,</b>		<b>Three Months Ended March 31,</b>	
	<b>2018</b>	<b>2017</b>	<b>2018</b>	<b>2017</b>
	<b>(in thousands)</b>		<b>(per Boe)</b>	
<b>EXPENSES:</b>				
Lease operating and workover	\$ 14,808	\$ 15,852	\$ 8.56	\$ 7.47
Gathering and transportation	57	3,687	0.03	1.74
Severance and other taxes	2,861	2,121	1.65	1.00
Asset retirement accretion	297	276	0.17	0.13
Depreciation, depletion, and amortization	15,213	15,342	8.79	7.23
General and administrative	9,857	8,275	5.70	3.90
<b>Total expenses</b>	<b>\$ 43,093</b>	<b>\$ 45,553</b>	<b>\$ 24.90</b>	<b>\$ 21.47</b>

*Lease Operating and Workover*

Lease operating and workover expenses decreased \$1.1 million, or 6.6%, to \$14.8 million for the three months ended March 31, 2018 compared to \$15.9 million for the three months ended March 31, 2017. During the three months ended March 31, 2017 we received an insurance reimbursement in the amount of \$1.9 million that was recorded as a reduction of lease operating expenses. Further, the three months ended March 31, 2017 included \$0.7 million in lease operating and workover expense related to Lincoln County properties, which we sold during 2017. After consideration of the insurance proceeds and the sale of Lincoln County properties, lease operating and workover expenses decreased \$2.3 million, or 13.2%. This change was largely as a result of decreased third-party contract labor and service as well as the impact of decreased production. Lease operating and workover expenses increased to \$8.56 per Boe during the three months ended March 31, 2018 from \$7.47 per Boe during the related period in 2017, an increase of \$1.09 per Boe, or 14.6%, largely as a result of decreased production.

Table of Contents*Gathering and Transportation*

Gathering and transportation expenses decreased \$3.6 million, or 98.5%, to \$0.1 million for the three months ended March 31, 2018 compared to \$3.7 million for the three months ended March 31, 2017. On January 1, 2018, we adopted ASC 606 and as a result \$3.0 million in gathering and transportation expenses for the three months ended March 31, 2018 are reflected as a decrease in oil, NGLs and natural gas sales in the unaudited condensed consolidated statements of operations. Gathering and transportation excluding adjustments for ASC 606 decreased \$0.6 million, or 16.7%, to \$3.1 million for the three months ended March 31, 2018, compared to \$3.7 million for the three months ended March 31, 2017, due to a decrease in natural gas production in our Mississippian Lime asset.

*Severance and Other Taxes*

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
<b>Total oil, natural gas, and natural gas liquids sales</b>	<b>\$ 51,789</b>	<b>\$ 59,328</b>
Severance taxes	2,681	1,897
Ad valorem and other taxes	180	224
<b>Severance and other taxes</b>	<b>\$ 2,861</b>	<b>\$ 2,121</b>
<b>Severance taxes as a percentage of sales</b>	<b>5.2%</b>	<b>3.2%</b>
<b>Severance and other taxes as a percentage of sales</b>	<b>5.5%</b>	<b>3.6%</b>

Severance and other taxes increased \$0.7 million, or 34.9%, to \$2.9 million for the three months ended March 31, 2018 compared to \$2.1 million for the three months ended March 31, 2017. Severance taxes increased \$0.8 million, or 41.3%, to \$2.7 million for the three months ended March 31, 2018, as compared to \$1.9 million for the three months ended March 31, 2017. Severance taxes as a percentage of sales changed from 3.2% for the three months ended March 31, 2017 to 5.2% for the corresponding 2018 period 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 \$3.0 million of gathering and transportation expenses in oil, NGLs and natural gas sales for the three months ended March 31, 2018 also impacted the severance and other taxes rate by 0.4%.

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 beginning in July 2018.

*Depreciation, Depletion and Amortization*

Depreciation, depletion and amortization expense decreased \$0.1 million, or 1.0%, to \$15.2 million for the three months ended March 31, 2018, compared to \$15.3 million for the three months ended March 31, 2017. Depreciation, depletion and amortization per Boe increased \$1.56 per Boe during the three months ended March 31, 2018, to \$8.79 per Boe from \$7.23 per Boe for the three months ended March 31, 2017. Our depletion rate has increased from approximately 1.1% for the three months ended March 31, 2017, to 1.5% for the three months ended

## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

March 31, 2018, primarily as a result of decreased proved reserves volumes from the prior year.

### *General and Administrative ( G&A )*

G&A expenses increased \$1.6 million, or 19.1%, to \$9.9 million for the three months ended March 31, 2018 compared to \$8.3 million for the three months ended March 31, 2017. The increase in G&A expenses is primarily due to the Company's review of various strategic options, which resulted in \$2.3 million in costs as well as employee severance costs related to a reduction-in-force that occurred on January 24, 2018 in the amount of \$1.6 million. These increases were partially offset by \$1.6 million in lower stock compensation expense.

Table of Contents*Other Expense*

	For the Three Months Ended March 31,	
	2018	2017
	(in thousands)	
<b>OTHER EXPENSE</b>		
Interest income	\$ 19	\$
Interest expense	(1,796)	(1,820)
Amortization of deferred financing costs	(108)	(80)
Amortization of deferred gain		
Capitalized interest	77	923
Interest expense net of amounts capitalized	(1,827)	(977)
<b>Total other expense</b>	<b>\$ (1,808)</b>	<b>\$ (977)</b>

*Interest Expense*

Interest expense was \$1.8 million for the three months ended March 31, 2018 and 2017, respectively. Our average outstanding balance under our revolving credit facility was \$113.1 million during the three months ended March 31, 2018, compared to \$128.1 million for the three months ended March 31, 2017, due to the \$50.0 million paydown of the RBL in March of 2018. Total interest expense capitalized to oil and gas properties was \$0.1 million and \$0.9 million for the three months ended March 31, 2018 and 2017, respectively. The reduction in capitalized interest was due to a \$45.5 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 during the three months ended March 31, 2018 or 2017, respectively, due to the change in our valuation allowance recorded against our net deferred tax assets. Our valuation allowance was \$119.0 million and \$153.6 million at March 31, 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):

March 31, 2018

December 31, 2017

## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

Cash and cash equivalents	\$	8,428	\$	68,498
Net working capital (deficit)		(12,278)		48,866
Total long-term debt		78,059		128,059
Total stockholders' equity		491,928		485,587
Available borrowing capacity		90,000		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.

Table of Contents

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 March 31, 2018, in addition to cash on hand of \$8.4 million, we maintained the RBL. The RBL has a current borrowing base of \$170.0 million. At March 31, 2018, we had \$78.1 million drawn on the RBL and outstanding letters of credit obligations totaling \$1.9 million. As a result, at March 31, 2018, we had \$90.0 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. At March 31, 2018, the weighted average interest rate, including amortization expense of deferred financing costs, was 6.9%.

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;



## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

(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 March 31, 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 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):

	<b>For the Three Months Ended March 31, 2018</b>		<b>For the Three Months Ended March 31, 2017</b>	
Net cash provided by operating activities	\$	22,147	\$	32,373
Net cash used in investing activities		(31,758)		(24,758)
Net cash used in financing activities		(50,459)		
<b>Net change in cash</b>	<b>\$</b>	<b>(60,070)</b>	<b>\$</b>	<b>7,615</b>

Table of Contents

*Cash flows provided by operating activities*

Net cash provided by operating activities was \$22.1 million and \$32.4 million for the three months ended March 31, 2018 and 2017, respectively. The decrease in net cash provided by operating activities was primarily the result of a \$7.3 million decrease in revenues from contracts with customers, payments made for the settlement of certain derivatives of \$0.2 million as compared to receipts of derivative settlements of \$0.8 million and a decrease in the change of working capital of \$2.4 million.

*Cash flows used in investing activities*

Net cash used in investing activities of \$31.8 million and \$24.8 million for the three months ended March 31, 2018 and 2017, respectively. Substantially all of our capital spend is invested into our Mississippi Lime asset, and the decrease year over year is the result of our reduced drilling activity in that area.

*Cash flows provided by financing activities*

Net cash used in financing activities was \$50.5 million for the three months ended March 31, 2018. During the three months ended March 31, 2018, we paid down \$50.0 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 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**

## Edgar Filing: Midstates Petroleum Company, Inc. - Form 10-Q

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.

Table of Contents

*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 March 31, 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 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 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 RBL. 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 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 No. 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 ASC 740 *Income Taxes*. 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.

Table of Contents

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows – Classification of Certain Cash Receipts and Cash Payments*. ASU 2016-15 addresses eight specific cash flow issues with the objective of reducing existing diversity of practice. The eight specific cash flow issues contained within ASU 2016-15 are debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The adoption of ASU 2016-15 did not have a material impact on our statements of cash flows.

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.

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 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 its 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 in the initial evaluation stage for ASU 2016-02 and related interpretations and guidance. 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.

Table of Contents

**ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.**

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

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses or gains, but rather indicators of reasonably possible losses or gains. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. These derivative instruments are discussed in Part I. Financial Information Item 1. Financial Statements Notes to the Unaudited Condensed Consolidated Financial Statements Note 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 March 31, 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 March 31, 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)	
<b>Gain (loss):</b>		
Gas derivatives	\$ (2,458)	\$ 2,359
Oil derivatives	\$ (9,883)	\$ 8,463

*Interest Rate Risk*



At March 31, 2018, we had indebtedness outstanding under our RBL of \$78.1 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 March 31, 2018 would have resulted in a \$1.7 million increase in annual interest cost, before capitalization.

At March 31, 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.

Table of Contents

**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 Chief Executive Officer and Vice President and Chief Accounting Officer concluded that as of March 31, 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 March 31, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents**PART II - OTHER INFORMATION****Item 1. Legal Proceedings**

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

**Item 1A. Risk Factors**

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

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 first 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
January 1, 2018 - January 31, 2018		\$
February 1, 2018 - February 28, 2018	100,293	\$ 16.34
March 1, 2018 - March 31, 2018	2,466	\$ 13.71
<b>Total</b>	102,759	\$ 16.28

**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.

Table of Contents

**EXHIBIT INDEX**

<b>Exhibit Number</b>	<b>Exhibit Description</b>
2.1	<u>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).</u>
3.1	<u>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).</u>
3.2	<u>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).</u>
4.1	<u>Warrant Agreement, dated as of October 21, 2016, between Midstates Petroleum Company, Inc. and American Stock Transfer &amp; 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).</u>
4.2	<u>Warrant Agreement, dated as of October 21, 2016, between Midstates Petroleum Company, Inc. and American Stock Transfer &amp; 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).</u>
10.1	<u>Separation Agreement and General Release, dated as of January 24, 2018, by and between Midstates Petroleum Company, Inc. and Mitchell G. Elkins (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 26, 2018, and incorporated herein by reference).</u>
10.2*	<u>Purchase and Sale Agreement, dated as of March 29, 2018, by and among Midstates Petroleum Company, Inc. and Presidio Investment Holdings LLC.</u>
31.1*	<u>Sarbanes-Oxley Section 302 certification of Principal Executive Officer.</u>
31.2*	<u>Sarbanes-Oxley Section 302 certification of Principal Financial Officer.</u>
32.1**	<u>Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer.</u>
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



Table of Contents

**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: May 10, 2018

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

Dated: May 10, 2018

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