SILVERBOW RESOURCES, INC.
Form 10-Q
August 08, 2018

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

FORM 10-Q

(X) Quarterly Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2018
Commission File Number 1-8754
SILVERBOW RESOURCES, INC.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

575 North Dairy Ashford, Suite 1200
Houston, Texas 77079
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

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, and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definition of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer o Accelerated Filer þ Non-Accelerated Filer o Smaller Reporting Company o
Emerging Growth Company o

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

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

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Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d)of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.
YesþNo o

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date.
Common Stock ($.01 Par Value) (Class of Stock) 11,667,165 Shares outstanding at August 1, 2018

Explanatory Note

On May 5, 2017, through an amendment to its Certificate of Incorporation and Bylaws, Swift Energy Company changed its name to SilverBow Resources, Inc. Additionally, SilverBow Resources, Inc. began trading on the New York Stock Exchange ("NYSE") under the symbol "SBOW" on May 5, 2017.

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SILVERBOW RESOURCES, INC.

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2018
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Condensed Consolidated Balance Sheets (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except share amounts)

	June 30, 2018	December 31, 2017
ASSETS		
Current Assets:		
Cash and cash equivalents	$6,611	$ 7,806
Accounts receivable, net	22,057	27,263
Fair value of commodity derivatives	1,775	5,148
Other current assets	3,090	2,352
Total Current Assets	33,533	42,569
Property and Equipment:		
Property and Equipment, full cost method, including $53,865 and $50,377 of unproved property costs not being amortized at the end of each period	796,052	712,166
Less – Accumulated depreciation, depletion, amortization & impairment	(242,997)	(216,769)
Property and Equipment, Net	553,055	495,397
Fair value of long-term commodity derivatives	3,332	2,553
Other Long-Term Assets	7,076	10,751
Total Assets	$596,996	$ 551,270
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$35,350	$ 44,437
Fair value of commodity derivatives	11,742	5,075
Accrued capital costs	41,821	10,883
Accrued interest	2,597	2,106
Undistributed oil and gas revenues	10,953	12,996
Total Current Liabilities	102,463	75,497
Long-Term Debt, net	274,577	265,325
Deferred Tax Liabilities	328	—
Asset Retirement Obligations	4,258	8,678
Fair value of long-term commodity derivatives	5,427	2,758
Other Long-Term Liabilities	2,500	5,554
Commitments and Contingencies (Note 11)		
Stockholders' Equity:		
Preferred stock, $.01 par value, 10,000,000 shares authorized, none issued	—	—
Common stock, $.01 par value, 40,000,000 shares authorized, 11,733,036 and 11,621,385 shares issued and 11,667,165 and 11,570,621 shares outstanding, respectively	117	116
Additional paid-in capital	282,726	279,111
Treasury stock, held at cost, 65,871 and 50,764 shares	(1,870)	(1,452)
Retained earnings (Accumulated deficit)	(73,530)	(84,317)
Total Stockholders' Equity	207,443	193,458
Total Liabilities and Stockholders' Equity	$596,996	$ 551,270

See accompanying Notes to Condensed Consolidated Financial Statements.

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Condensed Consolidated Statements of Operations (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except per-share amounts)

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
Revenues:		
Oil and gas sales	$51,347	$45,782
Operating Expenses:		
General and administrative, net	5,794	6,811
Depreciation, depletion, and amortization	13,096	10,828
Accretion of asset retirement obligations	84	576
Lease operating costs	3,760	4,776
Transportation and gas processing	5,421	4,761
Severance and other taxes	2,662	2,280
Total Operating Expenses	30,817	30,032
Operating Income (Loss)	20,530	15,750
Non-Operating Income (Expense)		
Gain (loss) on commodity derivatives, net	(10,752)	5,132
Interest expense, net	(6,585)	(4,642)
Other income (expense), net	(546)	1
Income (Loss) Before Income Taxes	2,647	16,241
Provision (Benefit) for Income Taxes	328	—
Net Income (Loss)	$2,319	$16,241
Per Share Amounts-		
Basic: Net Income (Loss)	$0.20	$1.41
Diluted: Net Income (Loss)	$0.20	$1.41
Weighted Average Shares Outstanding - Basic	11,655	11,487
Weighted Average Shares Outstanding - Diluted	11,757	11,554

See accompanying Notes to Condensed Consolidated Financial Statements.

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Condensed Consolidated Statements of Operations (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except per-share amounts)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Revenues:		
Oil and gas sales	$104,099	$88,194
Operating Expenses:		
General and administrative, net	11,370	16,645
Depreciation, depletion, and amortization	26,228	20,543
Accretion of asset retirement obligations	243	1,140
Lease operating costs	8,721	10,549
Transportation and gas processing	10,446	9,146
Severance and other taxes	5,692	3,898
Total Operating Expenses	62,700	61,921
Operating Income (Loss)	41,399	26,273
Non-Operating Income (Expense)		
Gain (loss) on commodity derivatives, net	(17,107)	16,068
Interest expense, net	(12,474)	(8,249)
Other income (expense), net	(703)	(141)
Income (Loss) Before Income Taxes	11,115	33,951
Provision (Benefit) for Income Taxes	328	—
Net Income (Loss)	$10,787	$33,951
Per Share Amounts-		
Basic: Net Income (Loss)	$0.93	$2.99
Diluted: Net Income (Loss)	$0.92	$2.97
Weighted Average Shares Outstanding - Basic	11,629	11,360
Weighted Average Shares Outstanding - Diluted	11,742	11,445

See accompanying Notes to Condensed Consolidated Financial Statements.

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Condensed Consolidated Statements of Stockholders’ Equity (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except share amounts)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total
Balance, December 31, 2016	$ 101	$232,917	$(675)	$ (156,288)	$76,055
Purchase of treasury shares (28,279 shares)	—	—	(777)	—	(777)
Issuance common stock (1,403,508 shares)	14	39,166	—	—	39,180
Issuance of restricted stock (141,818 shares)	1	(1)	—	—	—
Share-based compensation	—	7,029	—	—	7,029
Net Income	—	—	—	71,971	71,971
Balance, December 31, 2017	$ 116	$279,111	$(1,452)	$ (84,317)	$193,458
Shares issued from option exercise (29,199 shares)	—	708	—	—	708
Purchase of treasury shares (15,107 shares)	—	—	(418)	—	(418)
Issuance of restricted stock (82,452 shares)	1	(1)	—	—	—
Share-based compensation	—	2,908	—	—	2,908
Net Income	—	—	—	10,787	10,787
Balance, June 30, 2018	$ 117	$282,726	$(1,870)	$ (73,530)	$207,443

See accompanying Notes to Condensed Consolidated Financial Statements.

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Condensed Consolidated Statements of Cash Flows (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Cash Flows from Operating Activities:		
Net income (loss)	$10,787	$33,951
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities		
Depreciation, depletion, and amortization	26,228	20,543
Accretion of asset retirement obligations	243	1,140
Deferred income taxes	328	—
Share-based compensation expense	2,675	3,136
(Gain) Loss on derivatives, net	17,107	(16,068)
Cash settlement (paid) received on derivatives	(1,935)	(2,586)
Settlements of asset retirement obligations	(144)	(1,894)
Write down of debt issuance cost	—	2,401
Other	3,374	482
Change in operating assets and liabilities-		
(Increase) decrease in accounts receivable and other current assets	2,332	(1,486)
Increase (decrease) in accounts payable and accrued liabilities	(8,439)	4,437
Increase (decrease) in accrued interest	491	(90)
Net Cash Provided by (used in) Operating Activities	53,047	43,966
Cash Flows from Investing Activities:		
Additions to property and equipment	(84,097)	(85,655)
Proceeds from the sale of property and equipment	26,924	460
Payments on property sale obligations	(6,042)	—
Transfer of company funds from restricted cash	—	(15)
Net Cash Provided by (Used in) Investing Activities	(63,215)	(85,210)
Cash Flows from Financing Activities:		
Proceeds from bank borrowings	122,300	300,000
Payments of bank borrowings	(113,300)	(287,000)
Net proceeds from issuances of common stock	708	39,244
Purchase of treasury shares	(418)	(618)
Payments of debt issuance costs	(317)	(4,073)
Net Cash Provided by (Used in) Financing Activities	8,973	47,553
Net increase (decrease) in Cash, Cash Equivalents and Restricted Cash	(1,195)	6,309
Cash, Cash Equivalents and Restricted Cash, at Beginning of Period	8,026	497
Cash, Cash Equivalents and Restricted Cash at End of Period	$6,831	$6,806
Supplemental Disclosures of Cash Flow Information:		
Cash paid during period for interest, net of amounts capitalized	$10,926	$8,847
Changes in capital accounts payable and capital accruals	$35,299	$5,356
Changes in other long-term liabilities for capital expenditures	$(2,500)	$—

See accompanying Notes to Condensed Consolidated Financial Statements

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Notes to Condensed Consolidated Financial Statements (Unaudited)
SilverBow Resources, Inc. and Subsidiaries

(1) General Information

SilverBow Resources, Inc. ("SilverBow," the "Company," or "we") is a growth oriented independent oil and gas company headquartered in Houston, Texas. The Company's strategy is focused on acquiring and developing assets in the Eagle Ford Shale located in South Texas. Being a committed and long-term operator in South Texas, the Company possesses a significant understanding of the reservoirs in the region. We leverage this competitive understanding to assemble high quality drilling inventory while continuously enhancing our operations to maximize returns on capital invested.

The condensed consolidated financial statements included herein are unaudited and have been prepared by the Company and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States ("GAAP") have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017 as filed with the Securities and Exchange Commission on March 1, 2018.

(2) Summary of Significant Accounting Policies

Basis of Presentation. The consolidated financial statements included herein have been prepared by SilverBow, and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation.

Principles of Consolidation. The accompanying condensed consolidated financial statements include the accounts of SilverBow and its wholly-owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and gas properties, with a focus on oil and natural gas reserves in the Eagle Ford trend in Texas. Our undivided interests in oil and gas properties are accounted for using the proportionate consolidation method, whereby our proportionate share of the assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying condensed consolidated financial statements.

Subsequent Events. We have evaluated subsequent events requiring potential accrual or disclosure in our condensed consolidated financial statements. There were no material subsequent events requiring additional disclosure in these condensed consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. Such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows there-from, and the ceiling test impairment calculation,

- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates in the calculation of share-based compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations,
- estimates in the calculation of the fair value of commodity derivative assets and liabilities,

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- estimates in the assessment of current litigation claims against the Company, and
- estimates in amounts due with respect to open state regulatory audits.

While we are not currently aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which relate to prior periods. These types of adjustments cannot be currently estimated and are expected to be recorded in the period during which the adjustments are known.

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the three months ended June 30, 2018 and 2017, such internal costs capitalized totaled $1.0 million and $1.2 million, respectively. For the six months ended June 30, 2018 and 2017, such internal costs capitalized totaled $2.4 million and $2.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 6 of these condensed consolidated financial statements for further discussion on capitalized interest costs).

The "Property and Equipment" balances on the accompanying condensed consolidated balance sheets are summarized for presentation purposes. The following is a detailed breakout of our "Property and Equipment" balances (in thousands):

	June 30, 2018	December 31, 2017
Property and Equipment		
Proved oil and gas properties	$738,780	$ 658,519
Unproved oil and gas properties	53,865	50,377
Furniture, fixtures, and other equipment	3,407	3,270
Less – Accumulated depreciation, depletion, amortization & impairment	(242,997)	(216,769)
Property and Equipment, Net	$553,055	$ 495,397

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties-including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties-by an overall rate determined by dividing the physical units of oil and natural gas produced (which excludes natural gas consumed in operations) during the period by the total estimated units of proved oil and natural gas reserves (which excludes natural gas consumed in operations) at the beginning of the period. Future development costs are estimated on a property-by-property basis based on current economic conditions. The period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between two and 20 years. Repairs and maintenance are charged to expense as incurred.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are associated with unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

The quarterly calculations of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered. There was no write-down for each of the three months ended June 30, 2018 and 2017 and the six months ended June 30, 2018 and 2017.

If future capital expenditures outpace future discounted net cash flows in our reserve calculations, if we have significant declines in our oil and natural gas reserves volumes (which also reduces our estimate of discounted future net cash flows from proved oil and natural gas reserves) or if oil or natural gas prices decline, it is possible that non-cash write-downs of our oil and natural gas properties will occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be; therefore, we cannot estimate the amount of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices.

Revenue Recognition. The Company adopted the new revenue recognition standard for revenue from contracts from customers (ASC 606) effective January 1, 2018. See Note 3 in these condensed consolidated financial statements for further details.

Accounts Receivable, Net. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both June 30, 2018 and December 31, 2017, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At June 30, 2018, our "Accounts receivable" balance included $17.4 million for oil and gas sales, $1.1 million due from joint interest owners, $0.8 million for severance tax credit receivables and $2.8 million for other receivables. At December 31, 2017, our "Accounts receivable" balance included $20.1 million for oil and gas sales, $2.1 million due from joint interest owners, $2.1 million for severance tax credit receivables and $3.0 million for other receivables.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate, including our wells, in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to "General and administrative, net," on the accompanying condensed consolidated statements of operations. The amount of supervision fees charged for each of the six months ended June 30, 2018 and 2017 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $1.1 million for the three months ended June 30, 2018 and 2017 and $2.2 million and $2.3 million for the six months ended June 30, 2018 and 2017, respectively.

Income Taxes. Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likelihood of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At June 30, 2018, we did not have any accrued liability for uncertain tax positions and do not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

The Company was in a net deferred tax asset position at both June 30, 2018 and June 30, 2017 for United States federal income taxes. Management has determined that it is not more likely than not that the Company will realize future cash benefits from its remaining federal carryover items and, accordingly, has taken a full valuation allowance to offset its tax assets. Tax expense

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associated with federal income taxes was fully offset by adjustments to the valuation allowance. We recognized $0.3 million for deferred state income tax expense during the three and six months ended June 30, 2018. We did not recognize any deferred state income tax expense during the three and six months ended June 30, 2017.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the “Act”). The Act makes broad and complex changes to the U.S. tax code that includes, among other provisions, a permanent reduction of the U.S. federal corporate tax rate from 35% to 21% and a repeal of the alternative minimum tax regime, both effective January 1, 2018. Because of the Company’s net deferred tax asset and valuation allowance positions, these changes did not impact tax expense for the six months ended June 30, 2018.

The provisions of the Act, including its extensive transition rules, are complex and interpretive guidance continues to develop. The Company’s deferred tax balances and offsetting valuation allowance should be considered provisional. The final application of the Act to the Company’s tax computations may result in further adjustments. Changes could arise as regulatory and interpretive action continues to clarify aspects of the Act and as changes are made to estimates that the Company has utilized in calculating the transition impacts. The Company expects make any adjustments, if necessary, related to the impacts of this legislation by the end of 2018.

Accounts Payable and Accrued Liabilities. The “Accounts payable and accrued liabilities” balances on the accompanying condensed consolidated balance sheets are summarized below (in thousands):

	June 30, 2018	December 31, 2017
Trade accounts payable	$16,015	$ 20,884
Accrued operating expenses	2,316	3,490
Accrued compensation costs	2,945	5,334
Asset retirement obligations – current portion	303	2,109
Accrued non-income based taxes	5,137	3,898
Accrued corporate and legal fees	3,120	2,784
Other payables	5,514	5,938
Total accounts payable and accrued liabilities	$35,350	$ 44,437

Cash and Cash Equivalents. We consider all highly liquid instruments with an initial maturity of three months or less to be cash equivalents. These amounts do not include cash balances that are contractually restricted.

Long-term Restricted Cash. Long-term restricted cash includes amounts held in escrow accounts to satisfy plugging and abandonment obligations. As of each of June 30, 2018 and December 31, 2017, these assets were approximately $0.2 million. These amounts are restricted as to their current use and will be released when we have satisfied all plugging and abandonment obligations in certain fields. These restricted cash balances are reported in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheets.

The following table is a reconciliation of the total cash and cash equivalents and restricted cash in the accompanying condensed consolidated statement of cash flows and their corresponding balance sheet presentation (in thousands):

	June 30, 2018	December 31, 2017	June 30, 2017
Cash and cash equivalents	$6,611	$ 7,806	$6,627
Long-term restricted cash (1)	220	220	179
Total cash, cash equivalents and restricted cash	$6,831	$ 8,026	$6,806

(1) Long-term restricted cash is included in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheets.

Treasury Stock. Our treasury stock repurchases are reported at cost and are included in “Treasury stock held, at cost” on the accompanying condensed consolidated balance sheets. For the six months ended June 30, 2018, we purchased 15,107 treasury shares to satisfy withholding tax obligations arising upon the vesting of restricted shares.

Fresh Start Accounting. Upon emergence from bankruptcy on April 22, 2016, the Company adopted Fresh Start Accounting. As a result of the application of fresh start accounting, as well as the effects of the implementation of the joint plan of reorganization (the “Plan”), the Consolidated Financial Statements on or after April 22, 2016, are not comparable with the Consolidated Financial Statements prior to that date.

New Accounting Pronouncements. In February 2016, the Financial Accounting Standards Board (the “FASB”) issued Accounting Standards Updated (“ASU”) 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.

At December 31, 2017 the Company’s total lease commitments were approximately $6.2 million. There have been no material changes to our previously disclosed lease commitment amounts. Of this total, $2.0 million is related to our corporate office sub-lease which has a remaining term of approximately three years. The remaining commitments are generally for equipment and vehicle leases, most of which are expiring during 2018. The Company did not enter into any significant additional lease obligations during the first six months of 2018 and is in the process of evaluating other contracts that may contain lease components that need to be recognized under this standard. Management plans to adopt ASU 2016-02 in the quarter ending March 31, 2019. Management continuously evaluates the economics of leasing versus purchase for operating equipment. The lease obligations that will be in place upon adoption of ASU 2016-02 may be significantly different than the current obligations. Accordingly, at this time we cannot estimate the amount that will be capitalized when this standard is adopted.

In January 2017, the FASB issued ASU 2017-01, to assist entities in evaluating whether transactions should be accounted for as an acquisition or disposal of an asset or business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities are not a business. The guidance is effective for companies beginning January 1, 2018, with early adoption permitted. The Company has adopted this guidance as of January 1, 2018, and will apply it to any subsequent transactions.

(3) Revenue Recognition

Effective January 1, 2018, we adopted ASC 606 - Revenue from Contracts with Customers using the modified retrospective method of adoption. ASC 606 supersedes previous revenue recognition requirements in ASC 605. The new standard includes a five-step revenue recognition model to follow to determine the timing and amounts to be recognized as revenues in an entity’s financial statements. We have modified our processes and controls to ensure our reported oil and gas sales revenue is determined in accordance with this standard. Adoption of this standard did not result in a different amount reported for oil and gas sales than what we would have reported under the previous standard. Accordingly, there was no cumulative effect adjustment required upon adoption.

Virtually all of our revenue reported as oil and gas sales in our condensed consolidated statements of operations is derived from contracts. No other material revenue sources are attributable to Revenue from Contracts within the scope of ASC 606.

Revenue from Contracts with Customers

Our reported oil and gas sales are comprised of revenues from oil, natural gas and natural gas liquids (“NGLs”) sales. Revenues from each product stream are recognized at the point when control of the product is transferred to the customer and collectability is reasonably assured. Prices for our products are either negotiated on a monthly basis or tied to market indices. The Company has determined that these contracts represent performance obligations which are satisfied when control of the commodity transfers to the customer, typically through the delivery of the specified commodity to a designated delivery point. The types of contracts vary between product streams as described below:

Sales Contracts for Unprocessed Gas

We deliver natural gas to midstream entities at field delivery meter stations, under either transportation or processing agreements. For unprocessed gas (delivered under transportation or gathering agreements), we retain title to the gas through the redelivery points into downstream pipelines. The purchasers take title and control at these redelivery points. Sales proceeds are determined using the gas delivered for each monthly period based on an agreed upon index. We record the monthly proceeds realized at the redelivery points as gas sales revenue, and record the fees paid to the mid-stream pipeline as transportation expense.

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Contracts for Processed Gas and NGLs

NGLs are unique in that they remain in a gas state through normal field operations, and are typically part of the gas stream delivered to a gas processor. A gas processing facility is necessary to separate the NGLs from the gas. The most common NGL components are ethane, propane, butane, isobutane and pentane. Each of these NGL components has unique industrial and/or residential markets. Prices, which are typically quoted on a per gallon basis, can vary substantially between these products.

Where our raw gas contains commercially recoverable NGL components, we enter into agreements with midstream gas processors under which the processor takes delivery at meter stations in the field and transports the gas to its processing facility. The processing facility extracts the recoverable NGLs and the remaining natural gas ("residue gas") is delivered to a downstream pipeline, while the processor typically takes control of and purchases the NGLs at the plant tailgate.

We either take delivery of (take in kind) the residue gas at the plant tailgate and sell it to third party purchasers, or we sell the residue gas to the processor. Sales to third parties are negotiated on a monthly, seasonal or term basis and are priced at applicable market indexes. When we sell to the processor, the sales price is determined using monthly index prices.

When we sell the NGLs to the processor, each NGL component has a separate index price. The processor's statement segregates the individual component quantities and lists separate settlement amounts for each NGL component. The processor charges service or processing fees that are fixed in the processing agreement. We aggregate the revenue for all components and record NGL revenues as a single product.

Based on an analysis of the terms of our existing contracts, we determined that under substantially all of our processing agreements, we retain control of both the gas and NGLs through the processing facilities. As a result, the processor is both a service provider and a customer of the NGLs (and residue gas not sold to other parties) with the sales occurring at the plant outlet. Accordingly, we record gas and NGL sales at the value realized at the plant tailgate and record the processor's fees as transportation and processing expense.

Contracts for Oil sales

Under our oil sales contracts, we sell oil production at field delivery points at agreed-upon index pricing, adjusted for location differentials and product quality. Oil is priced on a per barrel basis. Oil is picked up by our purchasers' trucks at our tank batteries. Control transfers when it is loaded on the purchasers' trucks. We record oil revenue at the price received at the pick-up points.

Contract balances

Under our contracts we either invoice our customers on a monthly basis or receive monthly settlement statements from the purchasers. Invoices and settlement statements cover the products delivered during the calendar month. The performance obligation is deemed fully satisfied for each unit of product at the time control is transferred to the purchaser. Payment of each monthly settlement is unconditional. Accordingly, our product sales contracts do not give rise to any contract assets or liabilities connected to future performance obligations under ASC 606. Receivables for oil and gas sales are included in Accounts Receivable, net in the condensed consolidated balance sheets. See Note 2 above.

Settlements for performance obligations

We record revenue for the production delivered to the purchasers during each monthly accounting period. Settlements typically occur 30 - 60 days after the end of the delivery month. As a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. We have existing internal controls for our revenue estimation process and related accruals. Adjustments to prior period estimates were not material for the periods presented in our condensed consolidated statements of operations.

Transaction price allocated to remaining performance obligations

Our contract terms vary, with many being greater than one-year. The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14, applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Product prices under our long-term contracts (with delivery obligations greater than one month) are tied to indexes reflective of market value at the time of delivery.

Production imbalances

Previously, the Company elected to utilize the entitlements method to account for natural gas production imbalances which is no longer available under ASC 606. To comply with the new standard, natural gas revenues are recognized based on the actual volume of natural gas sold to the purchasers. We do not have any material imbalances, so this change had no impact on our reported revenues.

Oil and Gas sales by product

The following table provides information regarding our oil and gas sales, by product, reported on the Statements of Operations for the three months ended June 30, 2018 and 2017 and the six months ended June 30, 2018 and 2017 (in thousands):

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Oil, natural gas and NGLs sales:				
Oil	$9,638	$6,527	$21,078	$13,728
Natural gas	36,369	35,043	72,136	66,106
NGLs	5,339	4,215	10,900	8,363
Other	—	(3)	(14)	(3)
Total	$51,347	$45,782	$104,099	$88,194

(4) Share-Based Compensation

Share-Based Compensation Plans

Upon the Company's emergence from bankruptcy on April 22, 2016, the Company's previous share-based compensation plans were canceled and the new 2016 Equity Incentive Plan was approved in accordance with the joint plan of reorganization. Under the previous share-based compensation plan, the outstanding restricted stock awards and restricted stock unit awards for most employees vested on an accelerated basis while awards issued to certain officers of the Company and the Board of Directors were canceled in April 2016

For awards granted after emergence from bankruptcy, the Company does not estimate the forfeiture rate during the initial calculation of compensation cost but rather has elected to account for forfeitures in compensation cost when they occur.

The Company computes a deferred tax benefit for restricted stock awards, unit awards and stock options expected to generate future tax deductions by applying its effective tax rate to the expense recorded. For restricted stock units, the Company's actual tax deduction is based on the value of the units at the time of vesting.

The expense for awards issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations was $1.3 million and $1.6 million for the three months ended June 30, 2018 and 2017, respectively, and $2.7 million and $3.1 million for the six months ended June 30, 2018 and 2017, respectively. Capitalized share-based compensation was $0.1 million for each of the three months ended June 30, 2018 and 2017, and $0.2 million for each of the six months ended June 30, 2018 and 2017.

We view stock option awards and restricted stock unit awards with graded vesting as single awards with an expected life equal to the average expected life of component awards, and we amortize the awards on a straight-line basis over the life of the awards.

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Stock Option Awards

The compensation cost related to stock option awards is based on the grant date fair value and is typically expensed over the vesting period (generally one to five years). We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards.

At June 30, 2018, we had $3.9 million of unrecognized compensation cost related to stock option awards. The following table provides information regarding stock option award activity for the six months ended June 30, 2018:

	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	508,730	$26.82
Options granted	—	$—
Options forfeited	(21,319)	$29.96
Options expired	(8,356)	$26.96
Options exercised	(29,199)	$24.27
Options outstanding, end of period	449,856	$26.98
Options exercisable, end of period	141,347	$25.84

Our outstanding stock option awards at June 30, 2018 had $1.2 million of aggregate intrinsic value. At June 30, 2018, the weighted average remaining contract life of stock option awards outstanding was 6.6 years and exercisable was 3.6 years. The total intrinsic value of stock option awards exercisable for the six months ended June 30, 2018 was $0.5 million.

Restricted Stock Units

The 2016 equity incentive compensation plan allows for the issuance of restricted stock unit awards that generally may not be sold or otherwise transferred until certain restrictions have lapsed. The compensation cost related to these awards is based on the grant date fair value and is typically expensed over the requisite service period (generally one to five years).

As of June 30, 2018, we had unrecognized compensation expense of $7.3 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.6 years.

The following table provides information regarding restricted stock unit award activity for the six months ended June 30, 2018:

	Shares	Grant Date Price
Restricted stock units outstanding, beginning of period	346,740	$26.99
Restricted stock units granted	91,906	$27.89
Restricted stock units forfeited	(21,011)	$26.59
Restricted stock units vested	(81,754)	$25.04
Restricted stock units outstanding, end of period	335,881	$27.74

Performance-Based Stock Units

On February 20, 2018, the Company granted 30,700 performance-based stock units for which the number of shares earned is based on the Total Shareholder Return ("TSR") of the Company's common stock relative to the TSR of its selected peers ("Peer Group") during the performance period from January 1, 2018 to December 31, 2020 ("Performance Period"). The awards contain market conditions which allow a payout ranging between 0% payout and 200% of the target payout. The fair value as of the date of valuation was $41.66 per unit or 150.61% as a percentage of stock price with a remaining performance period of 2.7 years. The compensation expense for these awards is based on the per unit grant date valuation using a Monte-Carlo simulation multiplied by the target payout level. The payout level is calculated based on actual stock price performance achieved during the performance period. The awards have a cliff-vesting period of three years.

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As of June 30, 2018, we had unrecognized compensation expense of $1.1 million related to our performance-based stock units, which is expected to be recognized over a period of three years. No shares vested during the six months ended June 30, 2018.

(5) Earnings Per Share

Basic earnings per share (“Basic EPS”) has been computed using the weighted average number of common shares outstanding during each period. Diluted earnings per share ("Diluted EPS") assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Diluted EPS also assumes conversion of performance-based restricted stock units to common shares based on the number of shares (if any) that would be issuable, according to predetermined performance and market goals, if the end of the reporting period was the end of the performance period. Certain of our stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the three months ended June 30, 2018 and 2017 and the six months ended June 30, 2018 and 2017 are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic EPS and Diluted EPS for the periods indicated below (in thousands, except per share amounts):

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$2,319	11,655	$ 0.20	$16,241	11,487	$ 1.41
Dilutive Securities:						
Restricted Stock Awards		—			—	
Restricted Stock Unit Awards		16			59	
Stock Option Awards		86			8	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$2,319	11,757	$ 0.20	$16,241	11,554	$ 1.41

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$10,787	11,629	$ 0.93	$33,951	11,360	$ 2.99
Dilutive Securities:						
Restricted Stock Awards		—			—	
Restricted Stock Unit Awards		17			73	
Stock Option Awards		96			12	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$10,787	11,742	$ 0.92	$33,951	11,445	$ 2.97

Approximately 0.4 million stock options to purchase shares were not included in the computation of Diluted EPS for each of the three months ended June 30, 2018 and 2017 and the six months ended June 30, 2018 and 2017 because these stock options were antidilutive.

Less than 0.1 million and approximately 0.1 million shares of restricted stock units that could be converted to common shares were not included in the computation of Diluted EPS for the three months ended June 30, 2018 and 2017 because they were

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antidilutive. There were less than 0.1 million and approximately 0.1 million antidilutive shares of restricted stock units for the six months ended June 30, 2018 and 2017.

Less than 0.1 million shares of performance-based restricted stock units were not included in the computation of Diluted EPS for the three and six months ended June 30, 2018 because they were antidilutive.

Approximately 4.3 million warrants to purchase common stock were not included in the computation of Diluted EPS for the three months ended June 30, 2018 and 2017 and for the six months ended June 30, 2018 and 2017 because these warrants were antidilutive.

(6) Long-Term Debt

The Company's long-term debt consisted of the following (in thousands):

	June 30, 2018	December 31, 2017
Credit Facility Borrowings [1]	$82,000	$ 73,000
Second Lien Notes due 2024	200,000	200,000
	282,000	273,000
Unamortized discount on Second Lien Notes due 2024	(1,889)	(1,992)
Unamortized debt issuance cost on Second Lien Notes due 2024	(5,534)	(5,683)
Long-Term Debt, net	$274,577	$ 265,325

(1) Unamortized debt issuance costs on our Credit Facility borrowings are included in “Other Long-Term Assets” in our consolidated balance sheet. As of each of June 30, 2018 and December 31, 2017, we had $4.9 million and $5.5 million, respectively, in unamortized debt issuance costs on our Credit Facility borrowings.

Revolving Credit Facility. Amounts outstanding under our Credit Facility (defined below) were $82.0 million and $73.0 million as of each of June 30, 2018 and December 31, 2017, respectively. On April 19, 2017, the Company entered into a First Amended and Restated Senior Secured Revolving Credit Agreement among the Company, as borrower, JPMorgan Chase Bank, National Association, as administrative agent, and certain lenders party thereto, as amended, including the Third Amendment dated April 20, 2018 (the “Third Amendment to Credit Agreement”) to the First Amended and Restated Senior Secured Credit Agreement (as amended, the “Credit Agreement” and such facility, the “Credit Facility”). The Third Amendment to Credit Agreement reaffirmed the borrowing base at $330 million, decreased the applicable margin used to calculate the interest rate under the Credit Agreement by 50 basis points and carved out certain permitted basis differential swaps from the calculation of the maximum hedging covenant in the Credit Agreement.

The Credit Facility matures April 19, 2022, and provides for a maximum credit amount of $600 million. The borrowing base is regularly redetermined on or about May and November of each calendar year and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, each of the Company and the administrative agent may request an unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their discretion in accordance with their oil and gas lending criteria at the time of the relevant redetermination. The Company may also request the issuance of letters of credit under the Credit Agreement in an aggregate amount up to $25 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

Interest under the Credit Facility accrues at the Company’s option either at an Alternative Base Rate plus the applicable margin (“ABR Loans”) or the LIBOR Rate plus the applicable margin (“Eurodollar Loans”). As of April 20, 2018, the applicable margin ranges from 1.25% to 2.25% for ABR Loans and 2.25% to 3.25% for Eurodollar

Loans. The Alternate Base Rate and LIBOR Rates are defined, and the applicable margins are set forth, in the Credit Agreement. Undrawn amounts under the Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto.

The obligations under the Credit Agreement are secured, subject to certain exceptions, by a first priority lien on substantially all assets of the Company and certain of its subsidiaries, including a first priority lien on properties attributed with at least 85% of estimated proved reserves of the Company and its subsidiaries.

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The Credit Agreement contains the following financial covenants:

- a ratio of total debt to EBITDA, as defined in the Credit Agreement, for the most recently completed four fiscal quarters, not to exceed 4.0 to 1.0 as of the last day of each fiscal quarter; and

- a current ratio, as defined in the Credit Agreement, which includes in the numerator available borrowings undrawn under the borrowing base, of not less than 1.0 to 1.0 as of the last day of each fiscal quarter.

As of June 30, 2018, the Company was in compliance with all financial covenants under the Credit Agreement. Maintaining or increasing our borrowing base under our Credit Facility is dependent on many factors, including commodities pricing, our hedge positions and our ability to raise capital to drill wells to replaced produced reserves.

Additionally, the Credit Agreement contains certain representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitations on modifying organizational documents and material contracts. The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

Total interest expense on the Credit Facility, which includes commitment fees and amortization of debt issuance costs, was $1.6 million and $4.8 million for the three months ended June 30, 2018 and 2017, respectively, and $3.1 million and $8.5 million for the six months ended June 30, 2018 and 2017, respectively. The amount of commitment fee amortization included in interest expense, net was $0.3 million and $0.1 million for the three months ended June 30, 2018 and 2017, respectively, and $0.6 million and $0.2 million for the six months ended June 30, 2018 and 2017, respectively.

We capitalized interest on our unproved properties in the amount $0.3 million and $0.2 million for the three months ended June 30, 2018 and 2017, respectively, and $0.7 million and $0.4 million for the six months ended June 30, 2018 and 2017, respectively.

Senior Secured Second Lien Notes. On December 15, 2017, the Company entered into a note purchase agreement for Senior Secured Second Lien Notes (the “Second Lien”) among the Company as issuer, U.S. Bank National Association as agent and collateral agent (the “Second Lien Agent”), and certain holders that are a party thereto, and issued notes in an initial principal amount of $200 million, with a $2.0 million discount, for net proceeds of $198.0 million. The Company has the ability, subject to the satisfaction of certain conditions (including compliance with the Asset Coverage Ratio described below and the agreement of the holders to purchase such additional notes), to issue additional notes in a principal amount not to exceed $100 million. The Second Lien matures on December 15, 2024. On April 20, 2018 the Company entered into a First Amendment (the “First Amendment to the Second Lien”) which carves out certain permitted basis differential swaps from the calculation of the maximum hedging covenant in the Note Purchase Agreement.

Interest on the Second Lien is payable quarterly and accrues at LIBOR plus 7.5%; provided that if LIBOR ceases to be available, the Second Lien provides for a mechanism to use ABR (an alternate base rate) plus 6.5% as the applicable interest rate. The definitions of LIBOR and ABR are set forth in the Second Lien. To the extent that a payment, insolvency or, at the holders’ election, another default exists and is continuing, all amounts outstanding under the Second Lien will bear interest at 2.0% per annum above the rate and margin otherwise applicable thereto. Additionally, to the extent the Company were to default on the Second Lien, this would potentially trigger a cross-default under our Credit Facility.

The Company has the right, to the extent permitted under the Credit Facility and subject to the terms and conditions of the Second Lien, to optionally prepay the notes, subject to the following repayment fees: during years one and two, a customary "make-whole" amount (which is equal to the present value of the remaining interest payments through the twenty-four month anniversary of the issuance of the Second Lien, discounted at a rate equal to the Treasury Rate plus 50 basis points) plus 2.0% of the principal amount of the notes repaid; during year three, 2.0% of the principal amount of the Second Lien being prepaid; during year four, 1.0% of the principal amount of the Second Lien being prepaid; and thereafter, no premium. Additionally, the Second Lien contains customary mandatory prepayment obligations upon asset sales (including hedge terminations), casualty events and incurrences of certain debt, subject to, in certain circumstances, reinvestment periods. Management believes the probability of mandatory prepayment due to default is remote.

The obligations under the Second Lien are secured, subject to certain exceptions and other permitted liens (including the liens created under the Credit Facility), by a perfected security interest, second in priority to the liens securing our Credit Facility, and mortgage lien on substantially all assets of the Company and certain of its subsidiaries, including a mortgage lien on oil and gas properties attributed with at least 85% of estimated PV-9 of proved reserves of the Company and its subsidiaries and 85% of the book value attributed to the PV-9 of the non-proved oil and gas properties of the Company. PV-9 is determined using commodity price assumptions by the Administrative Agent of the Credit Facility.

The Second Lien contains an Asset Coverage Ratio, which is only tested (i) as a condition to issuance of additional notes and (ii) in connection with certain asset sales in order to determine whether the proceeds of such asset sale must be applied as a prepayment of the notes and includes in the numerator the PV-10 (defined below), based on forward strip pricing, plus the swap mark-to-market value of the commodity derivative contracts of the Company and its restricted subsidiaries and in the denominator the total net indebtedness of the Company and its restricted subsidiaries, of not less than 1.25 to 1.0 as of each date of determination (the “Asset Coverage Ratio Requirement”). PV-10 value is the estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%.

The Second Lien also contains a financial covenant measuring the ratio of total net debt to EBITDA, as defined in the Second Lien purchase agreement, for the most recently completed four fiscal quarters, not to exceed 4.5 to 1.0 as of the last day of each fiscal quarter. As of June 30, 2018, the Company was in compliance with all financial covenants under the Second Lien.

The Second Lien contains certain customary representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitations on modifying organizational documents and material contracts. The Second Lien contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Second Lien Facility to be immediately due and payable.

As of June 30, 2018, total net amounts recorded for the Second Lien were $192.6 million, net of unamortized debt discount and debt issuance costs. Interest expense on the Second Lien totaled $5.2 million and $10.0 million for the three and six months ended June 30, 2018.

Debt Issuance Costs. Our policy is to capitalize upfront commitment fees and other direct expenses associated with our line of credit arrangement and then amortize such costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings.

(7) Acquisitions and Dispositions

On March 1, 2018, the Company closed the sale of certain wells in its AWP Olmos field for proceeds, net of selling expenses, of $27.0 million. This transaction had an effective date of January 1, 2018. The buyer assumed approximately $6.3 million in asset retirement obligations. No gain or loss was recorded on the sale of this property.

Effective December 22, 2017, the Company closed a Purchase and Sale contract to sell the Company's wellbores and facilities in Bay De Chene and recorded a $16.3 million obligation related to the funding of certain plugging and abandonment costs as disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017. Of the $16.3 million original obligation, $6.0 million was paid during the six months ended June 30, 2018. Additionally, we reclassified $2.5 million in other long-term liabilities related to this sale to current liabilities. The remaining obligation under this contract is $10.2 million and is carried in the accompanying condensed consolidated balance sheet as of June 30, 2018. This balance is made up of $7.7 million of current liability, which is included in “Accrued capital costs,” and $2.5 million, which is included in “Other Long-Term Liabilities.”

There were no acquisitions or dispositions of developed properties during the three and six months ended June 30, 2017.

(8) Price-Risk Management Activities

Derivatives are recorded on the balance sheet at fair value with changes in fair value recognized in earnings. The changes in the fair value of our derivatives are recognized in "Net gain (loss) on commodity derivatives" on the accompanying condensed consolidated statements of operations. We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of commodity price swaps and collars as well as basis swaps.

During the three months ended June 30, 2018 and 2017, the Company recorded losses of $10.8 million and gains of $5.1 million, respectively, on its commodity derivatives. During the six months ended June 30, 2018 and 2017, the Company recorded losses of $17.1 million and gains of $16.1 million, respectively, on its commodity derivatives. The Company made net cash payments of $1.9 million and $2.6 million for settled derivative contracts during the six months ended June 30, 2018 and 2017, respectively.

At June 30, 2018 and December 31, 2017, we had less than $0.1 million and $2.2 million, respectively, in receivables for settled derivatives which were included on the accompanying condensed consolidated balance sheet in “Accounts receivable, net” and were subsequently collected in July 2018 and January 2018, respectively. At June 30, 2018 and December 31, 2017, we also had $1.6 million and $0.4 million, respectively, in payables for settled derivatives which were included on the accompanying condensed consolidated balance sheet in "Accounts payable and accrued liabilities" and were subsequently paid in July 2018 and January 2018, respectively.

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers. At June 30, 2018, there was $1.8 million and $3.3 million in current and long-term unsettled derivative assets and $11.7 million and $5.4 million in current and long-term unsettled derivative liabilities, respectively. At December 31, 2017, there was $5.1 million and $2.6 million in current and long-term unsettled derivative assets and $5.1 million and $2.8 million in current and long-term unsettled derivative liabilities, respectively.

The Company uses an International Swap and Derivatives Association master agreement for our derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company has elected to not offset the asset and liability fair value amounts of its derivatives on the accompanying balance sheets. Under the right of set-off, there was a $12.1 million net fair value liability at June 30, 2018 and a $0.1 million net fair value liability at December 31, 2017. For further discussion, related to the fair value of the Company's derivatives, refer to Note 9 of these condensed consolidated financial statements.

The following tables summarize the weighted average prices as well as future production volumes for our unsettled derivative contracts in place as of June 30, 2018:

Oil Derivative Swaps (NYMEX WTI Settlements)	Total Volumes (Bbls)	Weighted Average Price
2018 Contracts		
3Q18	130,400	$ 52.40
4Q18	122,800	$ 52.23
2019 Contracts		
1Q19	107,700	$ 52.77
2Q19	103,200	$ 52.72
3Q19	99,000	$ 52.79
4Q19	95,000	$ 52.73
2020 Contracts		
1Q20	81,300	$ 52.42
2Q20	77,850	$ 52.38
3Q20	74,700	$ 52.34
4Q20	72,000	$ 52.29

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Natural Gas Derivative Contracts (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Weighted Average Price
2018 Contracts		
3Q18	7,666,000	$ 2.88
4Q18	12,121,000	$ 2.96
2019 Contracts		
1Q19	7,516,000	$ 3.08
2Q19	6,060,000	$ 2.83
3Q19	5,550,000	$ 2.84
4Q19	5,966,000	$ 2.84
2020 Contracts		
1Q20	5,370,000	$ 2.83
2Q20	3,688,000	$ 2.76
3Q20	3,585,000	$ 2.76
4Q20	3,362,000	$ 2.77

NGL Contracts	Total Volumes (Bbls)	Weighted Average Price
2018 Contracts		
3Q18	112,200	$ 24.78
4Q18	148,200	$ 24.78

Natural Gas Basis Derivative Swap (East Texas Houston Ship Channel vs NYMEX Settlements)	Total Volumes (MMBtu)	Weighted Average Price
2018 Contracts		
3Q18	7,595,000	$ (0.01)
4Q18	11,850,000	$ (0.07)
2019 Contracts		
1Q19	11,310,000	$ (0.08)
2Q19	11,975,000	$ 0.04
3Q19	12,095,000	$ 0.03
4Q19	12,095,000	$ (0.04)
2020 Contracts		
1Q20	1,820,000	$ (0.10)
2Q20	1,820,000	$ (0.09)
3Q20	1,840,000	$ (0.07)
4Q20	1,840,000	$ (0.11)

Oil Basis Contracts	Total Volumes (Bbls)	Weighted Average Price
2018 Contracts		

3Q18	80,000	$ 4.13
4Q18	120,000	$ 4.13

(9) Fair Value Measurements

Fair Value on a Recurring Basis. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, Credit Facility and Second Lien. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities approximate fair value due to the highly liquid or short-term nature of these instruments.

The carrying value of our Credit Facility and Second Lien approximates fair value because the respective borrowing rates do not materially differ from market rates for similar borrowings. These are considered Level 3 valuations (defined below).

The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category have comparable fair values for identical instruments in active markets.

Level 2 – Uses quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets. Instruments in this category are periodically verified against quotes from brokers and include our commodity derivatives that we value using commonly accepted industry-standard models which contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data that are obtained from independent third-party sources.

Level 3 – Uses unobservable inputs for assets or liabilities that are in non-active markets.

The following table presents our assets and liabilities that are measured on a recurring basis at fair value as of each of June 30, 2018 and December 31, 2017, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 8 of these condensed consolidated financial statements.

	Fair Value Measurements at			
(in millions)	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
June 30, 2018				
Assets				
Natural Gas Derivatives	$4.5	$ —	$ 4.5	$ —
Natural Gas Basis Derivatives	$0.6	$ —	$ 0.6	$ —
Liabilities				
Natural Gas Derivatives	$1.7	$ —	$ 1.7	$ —
Natural Gas Basis Derivatives	$2.0	$ —	$ 2.0	$ —
Oil Derivatives	$12.0	$ —	$ 12.0	$ —
Oil Basis Derivatives	$0.2	$ —	$ 0.2	$ —
NGL Derivatives	$1.3	$ —	$ 1.3	$ —

December 31, 2017				
Assets				
Natural Gas Derivatives	$7.2	$ —	$ 7.2	$ —
Natural Gas Basis Derivatives	$0.3	$ —	$ 0.3	$ —
NGL Derivatives	$0.1	$ —	$ 0.1	$ —
Liabilities				
Natural Gas Derivatives	$1.3	$ —	$ 1.3	$ —
Natural Gas Basis Derivatives	$0.3	$ —	$ 0.3	$ —
Oil Derivatives	$5.2	$ —	$ 5.2	$ —
Oil Basis Derivatives	$0.1	$ —	$ 0.1	$ —
NGL Derivatives	$0.9	$ —	$ 0.9	$ —

Our current and long-term unsettled derivative assets and liabilities in the table above are measured at gross fair value and are shown on the accompanying condensed consolidated balance sheets in “Fair value of commodity derivatives” and “Fair value of long-term commodity derivatives,” respectively.

(10) Asset Retirement Obligations

Liabilities for legal obligations associated with the retirement obligations of tangible long-lived assets are initially recorded at fair value in the period in which they are incurred. When a liability is initially recorded, the carrying amount of the related asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized on a unit-of-production basis as part of depreciation, depletion, and amortization expense for our oil and gas properties. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the “Property and Equipment” balance on our accompanying condensed consolidated balance sheets. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

The following provides a roll-forward of our asset retirement obligations for the year ended December 31, 2017 and the six months ended June 30, 2018 (in thousands):

Asset Retirement Obligations as of December 31, 2016	$32,256
Accretion expense	2,322
Liabilities incurred for new wells and facilities construction	253
Reductions due to sold wells and facilities	(21,466)
Reductions due to plugged wells and facilities	(2,366)
Revisions in estimates	(212)
Asset Retirement Obligations as of December 31, 2017 (1)	$10,787
Accretion expense	243
Liabilities incurred for new wells and facilities construction	26
Reductions due to sold wells and facilities	(6,265)
Reductions due to plugged wells and facilities	(145)
Revisions in estimates	(85)
Asset Retirement Obligations as of June 30, 2018 (2)	$4,561

(1) Includes approximately $2.1 million of current asset retirement obligations included in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.
(2) Includes approximately $0.3 million of current asset retirement obligations included in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

(11) Commitments and Contingencies

In the ordinary course of business, we are party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual report on Form 10-K for the year ended December 31, 2017. The following information contains forward-looking statements; see “Forward-Looking Statements” on page 37 of this report.

Company Overview

SilverBow Resources is a growth oriented independent oil and gas company headquartered in Houston, Texas. The Company's strategy is focused on acquiring and developing assets in the Eagle Ford Shale located in South Texas where we have assembled approximately 100,000 net acres across five operating areas. Our acreage positions in each of our operating areas are highly contiguous and designed for optimal and efficient horizontal well development. We have built a balanced portfolio of properties with a significant base of current production and reserves coupled with low-risk development drilling opportunities and meaningful upside from newer operating areas.

Being a committed and long-term operator in South Texas, the Company possesses a significant understanding of the reservoir characteristics, geology, landowners and competitive landscape in the region. We leverage this in-depth knowledge to continue to assemble high quality drilling inventory while continuously enhancing our operations to maximize returns on capital invested.

We have transformed the Company from a conventional, Louisiana shallow water producer to a focused Eagle Ford player. Over the last few years we have successfully renegotiated midstream contracts, moved our headquarters to west Houston, and reduced headcount over 50%. We expect to continue our efforts to improve our G&A metrics as we execute on our strategic growth program. We continue to refine our portfolio, including the sale of certain AWP Olmos wells on March 1, 2018. This strategic divestiture allows us to better leverage existing personnel while lowering field-level costs on a per unit basis as it removes operational complexity from our portfolio. We believe there are other opportunities to continue streamlining our business to extract value for our shareholders.

Operational Results

Total production for the six months ended June 30, 2018 increased 14% from the six months ended June 30, 2017 to 160 Mmcfe/d primarily due to increased production from new wells in the Eagle Ford Shale, partially offset by the AWP Olmos divestiture and normal production declines. Natural gas production for the six months ended June 30, 2018 was 135 Mmcf/d, an increase of 15% from the six months ended June 30, 2017, primarily driven by increased activity levels in the Company’s Fasken area, combined with new activity in the Company’s Southern Eagle Ford gas window in Oro Grande, Uno Mas, and AWP. During the second quarter of 2018, the Company spud seven gross (seven net) wells while completing seven gross (six net) wells. The Company completed two well pads in its Oro Grande and AWP areas and completed three wells of a six well pad in Fasken during the quarter. This Fasken six well pad included three Upper Eagle Ford wells and three Lower Eagle Ford wells.

The Company plans on operating two rigs for the remainder of the year. The Company’s high specification rig, which was added in early March, will continue to focus on the western areas of the portfolio in Webb and Southwest LaSalle counties while the other rig focuses on our Southern Eagle Ford gas assets in LaSalle, McMullen and Live Oak Counties. The Company maintains considerable flexibility to modify the drilling program based on well results, commodity prices and other strategic opportunities. For the full year, the Company remains on track to drill 31-33 and complete 25-27 net wells, with the majority of the activity occurring in the second half of the year. The Company plans on drilling in all areas of its portfolio during 2018, with a continued focus on demonstrating the commercial viability of the Company’s extensive drilling inventory.

The Company continues to evaluate completion designs across its asset base assessing stage lengths, clusters per stage, fluid volumes, and proppant types/concentrations. The Company is integrating new concepts to improve asset performance, increase capital efficiency, and reduce operating costs. The Company completed two wells in its Oro Grande acreage during the second quarter. These wells were completed with an average of 3,700 pounds of proppant per foot of lateral, the Company’s highest intensity fracture stimulations to date.

In the second quarter, the Company also completed two wells in southern AWP, including the Bracken EF 26H which was the Company's second longest lateral at 9,220 feet. Both wells were completed using an average of 2,600 pounds of proppant per foot of lateral, with stage spacing of 170 feet. In addition, the Company finished operations on its first two 100% slickwater

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fracs, completing one Upper and one Lower Eagle Ford Fasken well in early July. These wells were stimulated with 2,500 pounds of proppant per foot of lateral. The Company has turned all four of these wells to production as of July of 2018.

In the month of July, the Company brought eight new wells to sales compared to two net wells in the second quarter.

2018 cost reduction initiatives: We continue to focus on cost efficient operations and took additional actions in the first six months of 2018 to reduce operating and overhead costs. These initiatives included field staff reductions, disposition of uneconomic and higher cost properties, full utilization of existing facilities, elimination of redundant equipment, and replacement of rental equipment with company-owned equipment. We have also improved our processes for drilling and completing wells. Our procurement team takes a diligent and systematic approach to reducing the total delivered costs of purchased services by examining costs at their most detailed level. Services are commonly sourced directly from the suppliers, which has led to a significant reduction in our overall lease operating expenses at the field level. For example, our South Texas lease operating expenses were $0.30/Mcfe for the first six months of 2018 which compared to $0.41/Mcfe for the same period a year ago. For the third quarter, we are guiding for lease operating expenses of $0.25 to $0.27, and we expect our metrics to improve throughout the year as production increases.

Additionally, our significant operational control and manageable leasehold obligations provide us the flexibility to control our costs as we transition to a development mode across our portfolio. At the corporate level, we have also undergone additional staff reductions, reduced the square footage of leased office space and are taking additional steps to further reduce overhead costs. These actions have led to cash general and administrative costs of $8.7 million (a non-GAAP financial measure calculated as $11.4 million in net general and administrative costs less $2.7 million of share based compensation) for the first six months of 2018 or $0.30 per Mcfe, compared to $13.5 million (a non-GAAP financial measure calculated as $16.6 million in net general and administrative costs less $3.1 million of share based compensation), or $0.53 per Mcfe, for the six months ended June 30, 2017.

Strategic dispositions: On March 1, 2018, the Company divested certain wells in its AWP Olmos field for $27.0 million in cash plus the assumption by the buyer of $6.3 million of asset retirement obligations. This transaction had an effective date of January 1, 2018. These assets are located in McMullen County, Texas and include approximately 491 wells with total proved reserves of 28 Bcfe (100% proved developed) as of December 31, 2017. Full year 2017 production from these properties was approximately 9.5 Mmcfe/d (57% natural gas). Cash proceeds from the sale were used to repay outstanding borrowings under the Company’s Credit Facility.

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Liquidity and Capital Resources

Our primary use of cash flow has been to fund capital expenditures to develop our oil and gas properties. We expect to make capital expenditures of $245 million to $265 million during 2018. We made $84 million of capital expenditures during the six months ended June 30, 2018, and capital expenditures are expected to increase in the third quarter of 2018 as a result of having two rigs running during the entire quarter. As of June 30, 2018, the Company's liquidity consisted of approximately $6.6 million of cash-on-hand and $248.0 million in available borrowings on our $330 million borrowing base under our Credit Facility. Management believes the Company has sufficient liquidity to meet its obligations during the next 12 months and execute its long-term development plans. See Note 6 to our condensed consolidated financial statements for more information on our Credit Facility and Second Lien.

Contractual Commitments and Obligations

During the first quarter of 2018, we incurred commitments of approximately $9.0 million for drilling services to be provided over the next year. We had no other material changes in our contractual commitments during the six months ended June 30, 2018 from amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2017.

Off-Balance Sheet Arrangements

As of June 30, 2018, we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K.

Summary of First Half 2018 Financial Results

- Revenues and net income (loss): The Company's oil and gas revenues were $104.1 million for the six months ended June 30, 2018, compared to $88.2 million for the six months ended June 30, 2017. Revenues were higher primarily due to overall increased production as well as higher oil and NGL pricing, partially offset by lower natural gas pricing. The Company's net income was $10.8 million for the six months ended June 30, 2018, compared to $34.0 million for the six months ended June 30, 2017. The decrease was primarily due losses on commodity derivatives.

- Capital expenditures: The Company's capital expenditures on a cash basis were $84.1 million for the six months ended June 30, 2018 compared to $85.7 million for the six months ended June 30, 2017. The expenditures for the six months ended June 30, 2018 were primarily driven by continued legacy development and Southern Eagle Ford gas window delineation, while expenditures for the six months ended June 30, 2017, were primarily driven by development activity at our Fasken and AWP fields in the Eagle Ford play.

- Working capital: The Company had a working capital deficit of $68.9 million at June 30, 2018 and a deficit of $32.9 million at December 31, 2017. The working capital computation does not include available liquidity through our Credit Facility.

- Cash Flows: For the six months ended June 30, 2018, the Company generated cash from operating activities of $53.0 million, of which $5.6 million was attributable to changes in working capital. Cash used for property additions was $84.1 million. This excluded $35.3 million attributable to a net increase of capital related payables and accrued costs. Additionally, $6.0 million was paid during six months ended June 30, 2018, for property sale obligations related to the sale of our former Bay De Chene field. The Company's net borrowings on the revolving Credit Facility were $9.0 million during the six months ended June 30, 2018.

For the six months ended June 30, 2017, the Company generated cash from operating activities of $44.0 million, of which $2.9 million was attributable to changes in working capital. Cash used for property additions was $85.7 million; however, this does not include $5.4 million attributable to a net increase of capital related payables and accrued costs. The Company’s net borrowings on the revolving Credit Facility were $13.0 million for this period. Additionally, for the six months ended June 30, 2017 the Company received $39.2 million from financing activities in connection with its share purchase agreement for the Company's common stock.

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Results of Operations

Revenues — Three Months Ended June 30, 2018 and Three Months Ended June 30, 2017

Natural gas production was 86% and 83% of our production volumes for the three months ended June 30, 2018 and 2017, respectively. Natural gas sales were 71% and 77% of oil and gas sales for the three months ended June 30, 2018 and 2017, respectively.

Crude oil production was 6% of our production volumes for each of the three months ended June 30, 2018 and 2017. Crude oil sales were 19% and 14% of oil and gas sales for the three months ended June 30, 2018 and 2017, respectively.

NGL production was 8% and 11% of our production volumes for the three months ended June 30, 2018 and 2017, respectively. NGL sales were 10% and 9% of oil and gas sales for the three months ended June 30, 2018 and 2017, respectively.

The following tables provide additional information regarding our oil and gas sales, by area, excluding any effects of our hedging activities, for the three months ended June 30, 2018 and 2017:

Fields	Three Months Ended June 30, 2018		Three Months Ended June 30, 2017	
	Oil and Gas Sales (In Millions)	Net Oil and Gas Production Volumes (MMcfe)	Oil and Gas Sales (In Millions)	Net Oil and Gas Production Volumes (MMcfe)
Artesia Wells	$11.6	2,290	$3.7	946
AWP	8.8	1,665	14.2	3,491
Fasken	25.3	8,644	27.5	8,717
Other (1)	5.6	1,941	0.4	128
Total	$51.3	14,540	$45.8	13,282

(1) Primarily composed of our Oro Grande and Uno Mas fields.

The sales volumes increase from 2017 to 2018 was primarily due to increased natural gas production and increased drilling and completion activity.

In the second quarter of 2018, our $5.6 million, or 12% increase, in oil, NGL and natural gas sales from the prior year period resulted from:

- Price variances that had an approximate $1.5 million favorable impact on sales due to the higher oil and NGL pricing, partially offset by lower natural gas pricing; and
- Volume variances that had an $4.0 million favorable impact on sales due to oil and natural gas production, partially offset by lower NGL production.

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The following table provides additional information regarding our oil and gas sales, by commodity type, as well as the effects of our hedging activities for derivative contracts held to settlement, for the three months ended June 30, 2018 and 2017 (in thousands, except per-dollar amounts):

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
Production volumes:		
Oil (MBbl) [(1)]	141	139
Natural gas (MMcf)	12,433	11,078
Natural gas liquids (MBbl) [(1)]	211	228
Total (MMcfe)	14,540	13,282
Oil, Natural gas and Natural gas liquids sales:		
Oil	$9,638	$6,527
Natural gas	36,369	35,043
Natural gas liquids	5,339	4,215
Total	$51,347	$45,785
Average realized price:		
Oil (per Bbl)	$68.53	$46.82
Natural gas (per Mcf)	2.93	3.16
Natural gas liquids (per Bbl)	25.36	18.49
Average per Mcfe	$3.53	$3.45
Price impact of cash-settled derivatives:		
Oil (per Bbl)	$(14.76)	$(0.11)
Natural gas (per Mcf)	(0.06)	(0.14)
Natural gas liquids (per Bbl)	(2.11)	—
Average per Mcfe	$(0.22)	$(0.12)
Average realized price including cash settled derivatives:		
Oil (per Bbl)	$53.76	$46.71
Natural gas (per Mcf)	2.87	3.02
Natural gas liquids (per Bbl)	23.25	18.49
Average per Mcfe	$3.31	$3.33

(1) Oil and natural gas liquids are converted at the rate of one barrel of oil equivalent to six Mcfe

For the three months ended June 30, 2018 and 2017, the Company recorded net losses of $10.8 million and net gains of $5.1 million from our derivative activities, respectively. Hedging activity is recorded in “Net gain (loss) on commodity derivatives” on the accompanying condensed consolidated statements of operations.

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Costs and Expenses — Three Months Ended June 30, 2018 and Three Months Ended June 30, 2017

The following table provides additional information regarding our expenses for the three months ended June 30, 2018 and 2017:

Costs and Expenses	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
General and administrative, net	$5,794	$6,811
Depreciation, depletion, and amortization	13,096	10,828
Accretion of asset retirement obligation	84	576
Lease operating cost	3,760	4,776
Transportation and gas processing	5,421	4,761
Severance and other taxes	2,662	2,280
Interest expense, net	6,585	4,642
Total Costs and Expenses	$37,402	$34,674

General and Administrative Expenses, Net. These expenses on a per Mcfe basis were $0.40 and $0.51 for the three months ended June 30, 2018 and 2017, respectively. The decrease was primarily due to lower salaries and burdens and decreases in other expenses as a result of our cost reduction initiatives. Included in general and administrative expenses is $1.3 million and $1.6 million in share based compensation for the three months ended June 30, 2018 and 2017, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses on a per Mcfe basis were $0.90 and $0.82 for the three months ended June 30, 2018 and 2017, respectively. The increase in the rate per unit is primarily due to a higher depletable base relative to reserves. The higher depletion expense is due to a higher production and a higher per unit rate.

Lease operating cost. These expenses on a per Mcfe basis were $0.26 and $0.36 for the three months ended June 30, 2018 and 2017, respectively. The decrease per Mcfe was primarily due to divestitures of assets and a concentrated effort by the Company to reduce overall operating costs.

Transportation and gas processing. These expenses are related to natural gas and NGL sales. These expenses on a per Mcfe basis were $0.37 and $0.36 for the three months ended June 30, 2018 and 2017, respectively.

Severance and Other Taxes. These expenses on a per Mcfe basis were $0.18 and $0.17 for the three months ended June 30, 2018 and 2017, respectively. Severance and other taxes, as a percentage of oil and gas sales, were approximately 5.2% and 5.0% for the three months ended June 30, 2018 and 2017.

Interest. Our gross interest cost was $6.8 million and $4.8 million for the three months ended June 30, 2018 and 2017, respectively. The increase in gross interest cost is primarily due to the interest on our Second Lien, partially offset by lower interest on our Credit Facility due to decreased borrowings. Interest cost of $0.3 million and $0.2 million was capitalized in the second quarters of 2018 and 2017, respectively.

Income Taxes. There was no expense for Federal income taxes in each of the three months ended June 30, 2018 and 2017 as the Company had significant deferred tax assets in excess of deferred tax liabilities. Because of uncertainty about the realization of any future tax benefits, the Company has carried a full valuation allowance against its Federal net deferred tax asset balance. Federal tax expense for income related to these periods was offset by reductions in our valuation allowance. We recognized $0.3 million for deferred state income tax expense during the three months ended June 30, 2018. There was no state income tax expense recorded for the three months ended June 30, 2017.

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Revenues — Six Months Ended June 30, 2018 and Six Months Ended June 30, 2017

Natural gas production was 84% and 83% of our production volumes for the six months ended June 30, 2018 and 2017, respectively. Natural gas sales were 69% and 75% of oil and gas sales for the six months ended June 30, 2018 and 2017, respectively.

Crude oil production was 7% of our production volumes for each of the six months ended June 30, 2018 and 2017. Crude oil sales were 20% and 16% of oil and gas sales for the six months ended June 30, 2018 and 2017, respectively.

NGL production was 9% and 10% of our production volumes for the six months ended June 30, 2018 and 2017, respectively. NGL sales were 11% and 9% of oil and gas sales for the six months ended June 30, 2018 and 2017, respectively.

The following tables provide additional information regarding our oil and gas sales, by area, excluding any effects of our hedging activities, for the six months ended June 30, 2018 and 2017:

Fields	Six Months Ended June 30, 2018		Six Months Ended June 30, 2017	
	Oil and Gas Sales (In Millions)	Net Oil and Gas Production Volumes (MMcfe)	Oil and Gas Sales (In Millions)	Net Oil and Gas Production Volumes (MMcfe)
Artesia Wells	$23.9	4,814	$7.9	1,962
AWP	20.9	4,117	27.8	6,637
Fasken	49.0	16,632	52.0	16,729
Other (1)	10.3	3,446	0.5	160
Total	$104.1	29,009	$88.2	25,488

(1) Primarily composed of our Oro Grande and Uno Mas fields.

The sales volumes increase from 2017 to 2018 was primarily due to increased natural gas production and increased drilling and completion activity.

In the first six months of 2018, our $15.9 million, or 18% increase, in oil, NGL and natural gas sales from the prior year period resulted from:

- Price variances that had an approximate $4.0 million favorable impact on sales due to the higher oil and NGL pricing, partially offset by lower natural gas pricing; and
- Volume variances that had an $11.9 million favorable impact on sales due to overall higher volume production.

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The following table provides additional information regarding our oil and gas sales, by commodity type, as well as the effects of our hedging activities for derivative contracts held to settlement, for the six months ended June 30, 2018 and 2017 (in thousands, except per-dollar amounts):

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Production volumes:		
Oil (MBbl) (1)	318	286
Natural gas (MMcf)	24,349	21,182
Natural gas liquids (MBbl) (1)	459	432
Total (MMcfe)	29,009	25,488
Oil, Natural gas and Natural gas liquids sales:		
Oil	$21,078	$13,728
Natural gas	72,136	66,106
Natural gas liquids	10,900	8,363
Total	$104,113	$88,197
Average realized price:		
Oil (per Bbl)	$66.33	$48.07
Natural gas (per Mcf)	2.96	3.12
Natural gas liquids (per Bbl)	23.75	19.36
Average per Mcfe	$3.59	$3.46
Price impact of cash-settled derivatives:		
Oil (per Bbl)	$(11.20)	$(1.50)
Natural gas (per Mcf)	0.07	(0.09)
Natural gas liquids (per Bbl)	(1.38)	—
Average per Mcfe	$(0.09)	$(0.09)
Average realized price including cash settled derivatives:		
Oil (per Bbl)	$55.13	$46.57
Natural gas (per Mcf)	3.03	3.03
Natural gas liquids (per Bbl)	22.38	19.36
Average per Mcfe	$3.50	$3.37

(1) Oil and natural gas liquids are converted at the rate of one barrel of oil equivalent to six Mcfe

For the six months ended June 30, 2018 and 2017, the Company recorded net losses of $17.1 million and net gains of $16.1 million from our derivative activities, respectively. Hedging activity is recorded in “Net gain (loss) on commodity derivatives” on the accompanying condensed consolidated statements of operations.

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Costs and Expenses — Six Months Ended June 30, 2018 and Six Months Ended June 30, 2017

The following table provides additional information regarding our expenses for the six months ended June 30, 2018 and 2017:

Costs and Expenses	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
General and administrative, net	$11,370	$16,645
Depreciation, depletion, and amortization	26,228	20,543
Accretion of asset retirement obligation	243	1,140
Lease operating cost	8,721	10,549
Transportation and gas processing	10,446	9,146
Severance and other taxes	5,692	3,898
Interest expense, net	12,474	8,249
Total Costs and Expenses	$75,174	$70,170

General and Administrative Expenses, Net. These expenses on a per Mcfe basis were $0.39 and $0.65 for the six months ended June 30, 2018 and 2017, respectively. The decrease was primarily due to lower salaries and burdens and decreases in other expenses as a result of our cost reduction initiatives. Included in general and administrative expenses is $2.7 million and $3.1 million in share based compensation for the six months ended June 30, 2018 and 2017, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses on a per Mcfe basis were $0.90 and $0.81 for the six months ended June 30, 2018 and 2017, respectively. The increase in the rate per unit is primarily due to a higher depletable base relative to reserves. The higher depletion expense is due to a higher production and a higher per unit rate.

Lease operating cost. These expenses on a per Mcfe basis were $0.30 and $0.41 for the six months ended June 30, 2018 and 2017, respectively. The decrease per Mcfe was primarily due to divestitures of assets and a concentrated effort by the Company to reduce overall operating costs.

Transportation and gas processing. These expenses are related to natural gas and NGL sales. These expenses on a per Mcfe basis were $0.36 for each of the six months ended June 30, 2018 and 2017.

Severance and Other Taxes. These expenses on a per Mcfe basis were $0.20 and $0.15 for the six months ended June 30, 2018 and 2017, respectively. Severance and other taxes, as a percentage of oil and gas sales, were approximately 5.5% and 4.4% for the six months ended June 30, 2018 and 2017. This increase is primarily due to an estimated increase in the taxable base for ad valorem tax and higher severance tax rates on new wells which realized a lower rate benefit under the Texas high cost well incentive program.

Interest. Our gross interest cost was $13.1 million and $8.6 million for the six months ended June 30, 2018 and 2017, respectively. The increase in gross interest cost is primarily due to the interest on our Second Lien, partially offset by lower interest on our Credit Facility due to decreased borrowings. Interest cost of $0.7 million and $0.4 million was capitalized in the second quarters of 2018 and 2017, respectively.

Income Taxes. There was no expense for Federal income taxes in each of the six months ended June 30, 2018 and 2017 as the Company had significant deferred tax assets in excess of deferred tax liabilities. Because of uncertainty about the realization of any future tax benefits, the Company has carried a full valuation allowance against its Federal net deferred tax asset balance. Federal tax expense for income related to these periods was offset by reductions in our valuation allowance. We recognized $0.3 million for deferred state income tax expense during the six months ended June 30, 2018. There was no state income tax expense recorded for the six months ended June 30, 2017.

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Non-GAAP Financial Measures

Adjusted EBITDA

We present adjusted EBITDA attributable to common stockholders ("Adjusted EBITDA") in addition to our reported net income (loss) in accordance with U.S. GAAP. Adjusted EBITDA is a non-GAAP financial measure that is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also used to assess our ability to incur and service debt and fund capital expenditures. We define Adjusted EBITDA as net income (loss):

Plus/(Less):
- Depreciation, depletion, amortization;
- Accretion of asset retirement obligations;
- Interest expense;
- Impairment of oil and natural gas properties;
- Net losses (gains) on commodity derivative contracts;
- Amounts collected (paid) for commodity derivative contracts held to settlement;
- Income tax expense (benefit); and
- Share-based compensation expense.

Our Adjusted EBITDA should not be considered an alternative to net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

The following tables present reconciliations of our net income (loss) to Adjusted EBITDA for the periods indicated (in thousands):

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017
Net Income (Loss)	$2,319	$16,241
Plus:		
Depreciation, depletion and amortization	13,096	10,828
Accretion of asset retirement obligations	84	576
Interest expense	6,585	4,642
Derivative (gain)/loss	10,752	(5,132)
Derivative cash settlements collected/(paid) [(1)]	(3,212)	(1,621)
Income tax expense/(benefit)	328	—
Share-based compensation expense	1,316	1,632
Adjusted EBITDA	$31,268	$27,166

(1) This includes accruals for settled contracts covering commodity deliveries during the period where the actual cash settlements occur outside of the period.

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net Income (Loss)	$10,787	$33,951
Plus:		
Depreciation, depletion and amortization	26,228	20,543
Accretion of asset retirement obligations	243	1,140
Interest expense	12,474	8,249
Derivative (gain)/loss	17,107	(16,068)
Derivative cash settlements collected/(paid) (1)	(2,476)	(2,289)
Income tax expense/(benefit)	328	—
Share-based compensation expense	2,675	3,136
Adjusted EBITDA	$67,366	$48,662

(1) This includes accruals for settled contracts covering commodity deliveries during the period where the actual cash settlements occur outside of the period.

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Critical Accounting Policies and New Accounting Pronouncements

Revenue Recognition. Effective January 1, 2018, we adopted ASC 606 - Revenue from Contracts with Customers using the modified retrospective method of adoption. Adoption of this standard did not result in any changes to our reporting. See Note 3 to our condensed consolidated financial statements for more information.

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized. We compute the provision for depreciation, depletion, and amortization (“DD&A”) of oil and natural gas properties using the unit-of-production method.

The costs of unproved properties not being amortized are assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of the impairment of unproved properties. The estimation process for both reserves and the impairment of unproved properties is subjective, and results may change over time based on current information and industry conditions. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months’ average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

If future capital expenditures outpace future discounted net cash flows in our reserve calculations, if we have significant declines in our oil and natural gas reserves volumes (which also reduces our estimate of discounted future net cash flows from proved oil and natural gas reserves) or if oil or natural gas prices decline, it is possible that non-cash write-downs of our oil and natural gas properties will occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices.

New Accounting Pronouncements. In February 2016, the FASB issued ASU 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. At this time, we do not anticipate the guidance to have a detrimental impact to our covenant compliance under our Credit Agreement. See Note 2 to our condensed consolidated financial statements for more information.

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Forward-Looking Statements

This report includes forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated production levels, expected oil and natural gas pricing, estimated oil and natural gas reserves or the present value thereof, reserve increases, capital expenditures, budget, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “budgeted,” “expect,” “may,” “continue,” “predict,” “potential,” “project” and similar expressions are intended to i forward-looking statements, although not all forward-looking statements contain such identifying words.

Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

• volatility in natural gas, oil and NGL prices;
• future cash flows and their adequacy to maintain our ongoing operations;
• liquidity, including our ability to satisfy our short- or long-term liquidity needs;
• our borrowing capacity, future covenant compliance, cash flows and liquidity;
• operating results;
• asset disposition efforts or the timing or outcome thereof;
• ongoing and prospective joint ventures, their structure and substance, and the likelihood of their finalization or the timing thereof;
• the amount, nature and timing of capital expenditures, including future development costs;
• timing, cost and amount of future production of oil and natural gas;
• availability of drilling and production equipment or availability of oil field labor;
• availability, cost and terms of capital;
• drilling of wells;
• availability and cost for transportation of oil and natural gas;
• costs of exploiting and developing our properties and conducting other operations;
• competition in the oil and natural gas industry;
• general economic conditions;
• opportunities to monetize assets;
• effectiveness of our risk management activities;
• environmental liabilities;
• counterparty credit risk;
• governmental regulation and taxation of the oil and natural gas industry;
• developments in world oil markets and in oil and natural gas-producing countries;
• uncertainty regarding our future operating results; and
• other risks and uncertainties described in Item 1A. “Risk Factors” in this quarterly report on Form 10-Q and our annual report on Form 10-K for the year ended December 31, 2017.

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2017. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release the results of any revisions to any such

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forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. This commodity pricing volatility has continued with unpredictable price swings in recent periods.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our Credit Facility. For additional discussion related to our price-risk management policy, refer to Note 8 of our condensed consolidated financial statements included in Item 1 of this report.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and when considered necessary, we also obtain letters of credit from certain customers, parent company guarantees if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Concentration of Sales Risk. A large portion of our oil and gas sales are made to Kinder Morgan and its affiliates and we expect to continue this relationship in the future. We believe that the business risk of this relationship is mitigated by the reputation and nature of their business and the availability of other purchasers.

Interest Rate Risk. At June 30, 2018, we had $82.0 million drawn under our Credit Facility which has a floating rate of interest and therefore is susceptible to interest rate fluctuations.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding such required disclosure. Our Chief Executive Officer and Chief Financial Officer have evaluated such disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the three months ended June 30, 2018, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

No material legal proceedings are pending other than ordinary, routine litigation incidental to the Company's business.

Item 1A. Risk Factors.

There have been no material changes in our risk factors disclosed in the 2017 Annual Report Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

None.

Item 5. Other Information.

None.

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Item 6. Exhibits.

The following exhibits in this index are required by Item 601 of Regulation S-K and are filed herewith or are incorporated herein by reference:

3.1	First Amended and Restated Certificate of Incorporation of SilverBow Resources, Inc., effective May 5, 2017 (incorporated by reference as Exhibit 3.1 to SilverBow Resources, Inc.'s Form 10-Q filed May 8, 2017, File No. 001-087541).
3.2	First Amended and Restated Bylaws of SilverBow Resources, Inc., effective May 5, 2017 (incorporated by reference as Exhibit 3.2 to SilverBow Resources, Inc.'s Form 10-Q filed May 8, 2017, File No. 001-08754).
10.1	Third Amendment to First Amended and Restated Senior Secured Revolving Credit Agreement dated as of April 20, 2018, by and among SilverBow Resources, Inc., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, the guarantors party thereto and certain lenders party thereto (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Current Report on Form 8-K filed April 25, 2018, File No. 001-08754).
10.2	First Amendment to Note Purchase Agreement dated as of April 20, 2018, by and among SilverBow Resources, Inc., as issuer, U.S. Bank National Association, as agent and collateral agent, the guarantors party thereto and the purchasers party thereto (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Current Report on Form 8-K filed April 25, 2018, File No. 001-08754).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*#	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*Filed herewith

+Management contract or compensatory plan or arrangement

Furnished herewith. Not considered to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

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SIGNATURES

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

		SILVERBOW RESOURCES, INC. (Registrant)
Date:	August 8, 2018	By: /s/ G. Gleeson Van Riet G. Gleeson Van Riet Executive Vice President and Chief Financial Officer
Date:	August 8, 2018	By: /s/ Gary G. Buchta Gary G. Buchta Controller