

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2018

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission file number: 001-35245



**SRC ENERGY INC.**

(Exact name of registrant as specified in its charter)

**COLORADO**

(State or other jurisdiction of incorporation or organization)

**20-2835920**

(I.R.S. Employer Identification No.)

**1675 Broadway, Suite 2600, Denver, CO**

(Address of principal executive offices)

**80202**

(Zip Code)

Registrant's telephone number, including area code: (720) 616-4300

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

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

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

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Large accelerated filer

Accelerated filer

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

Smaller reporting company

Emerging growth company

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 242,054,875 outstanding shares of common stock as of April 30, 2018.

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**SRC ENERGY INC.**

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**SRC ENERGY INC.**  
**CONDENSED CONSOLIDATED BALANCE SHEETS**  
(unaudited; in thousands, except share data)

<u>ASSETS</u>	March 31, 2018	December 31, 2017
Current assets:		
Cash and cash equivalents	\$ 71,743	\$ 48,772
Accounts receivable:		
Oil, natural gas, and NGL sales	93,732	86,013
Trade	18,718	18,134
Other current assets	6,944	7,116
Total current assets	191,137	160,035
Property and equipment:		
Oil and gas properties, full cost method:		
Proved properties, net of accumulated depletion	1,021,725	970,584
Wells in progress	149,214	106,269
Unproved properties and land, not subject to depletion	796,225	793,669
Oil and gas properties, net	1,967,164	1,870,522
Other property and equipment, net	5,945	6,054
Total property and equipment, net	1,973,109	1,876,576
Goodwill	40,711	40,711
Other assets	2,049	2,242
Total assets	\$ 2,207,006	\$ 2,079,564
<u>LIABILITIES AND SHAREHOLDERS' EQUITY</u>		
Current liabilities:		
Accounts payable and accrued expenses	\$ 106,509	\$ 74,672
Revenue payable	77,171	64,111
Production taxes payable	57,720	52,413
Asset retirement obligations	4,180	3,246
Commodity derivative liabilities	11,574	7,865
Total current liabilities	257,154	202,307
Revolving credit facility	—	—
Notes payable, net of issuance costs	538,471	538,186
Asset retirement obligations	25,330	28,376
Deferred taxes	5,811	—
Other liabilities	2,329	2,261
Total liabilities	829,095	771,130
Commitments and contingencies (See Note 15)		
Shareholders' equity:		
Preferred stock - \$0.01 par value, 10,000,000 shares authorized: no shares issued and outstanding	—	—
Common stock - \$0.001 par value, 300,000,000 shares authorized: 241,902,501 and 241,365,522 shares issued and outstanding as of March 31, 2018 and December 31, 2017, respectively	242	241
Additional paid-in capital	1,477,953	1,474,273
Retained deficit	(100,284)	(166,080)
Total shareholders' equity	1,377,911	1,308,434
Total liabilities and shareholders' equity	\$ 2,207,006	\$ 2,079,564

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

**SRC ENERGY INC.**  
**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**  
(unaudited; in thousands, except share and per share data)

	Three Months Ended March 31,	
	2018	2017
Oil, natural gas, and NGL revenues	\$ 147,233	\$ 43,790
Expenses:		
Lease operating expenses	7,896	3,722
Transportation and gathering	1,855	250
Production taxes	13,443	1,466
Depreciation, depletion, and accretion	37,081	13,229
Unused commitment charge	—	669
General and administrative	9,600	8,200
Total expenses	69,875	27,536
Operating income	77,358	16,254
Other income (expense):		
Commodity derivatives gain (loss)	(5,781)	3,379
Interest expense, net of amounts capitalized	—	—
Interest income	9	11
Other income	21	236
Total other income (expense)	(5,751)	3,626
Income before income taxes	71,607	19,880
Income tax expense	5,811	—
Net income	\$ 65,796	\$ 19,880
Net income per common share:		
Basic	\$ 0.27	\$ 0.10
Diluted	\$ 0.27	\$ 0.10
Weighted-average shares outstanding:		
Basic	241,751,915	200,707,891
Diluted	243,166,897	201,309,251

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

**SRC ENERGY INC.**  
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**  
(unaudited; in thousands)

	Three Months Ended March 31,	
	2018	2017
<b>Cash flows from operating activities:</b>		
Net income	\$ 65,796	\$ 19,880
<b>Adjustments to reconcile net income to net cash provided by operating activities:</b>		
Depletion, depreciation, and accretion	37,081	13,229
Settlement of asset retirement obligation	(2,461)	(764)
Provision for deferred taxes	5,811	—
Stock-based compensation expense	2,796	2,675
<b>Mark-to-market of commodity derivative contracts:</b>		
Total (gain) loss on commodity derivatives contracts	5,781	(3,379)
Cash settlements on commodity derivative contracts	(1,555)	81
<b>Changes in operating assets and liabilities:</b>	<b>14,432</b>	<b>(2,364)</b>
Net cash provided by operating activities	<u>127,681</u>	<u>29,358</u>
<b>Cash flows from investing activities:</b>		
Acquisition of oil and gas properties and leaseholds	(1,329)	(25,082)
Capital expenditures for drilling and completion activities	(100,347)	(55,464)
Other capital expenditures	(3,640)	(2,416)
Acquisition of land and other property and equipment	(317)	(2,072)
Proceeds from sales of oil and gas properties and other	728	70,689
Net cash used in investing activities	<u>(104,905)</u>	<u>(14,345)</u>
<b>Cash flows from financing activities:</b>		
Offering costs	(157)	—
Proceeds from the employee exercise of stock options	1,063	—
Payment of employee payroll taxes in connection with shares withheld	(475)	(431)
Proceeds from the revolving credit facility	—	20,000
Principal repayments on the revolving credit facility	—	(20,000)
Financing fees on issuance of notes payable and amendments to revolving credit facility	(149)	—
Capital lease payments	(87)	—
Net cash provided by (used in) financing activities	<u>195</u>	<u>(431)</u>
Net increase in cash, cash equivalents, and restricted cash	22,971	14,582
Cash, cash equivalents, and restricted cash at beginning of period	48,772	36,834
Cash, cash equivalents, and restricted cash at end of period	<u>\$ 71,743</u>	<u>\$ 51,416</u>
Supplemental Cash Flow Information (See Note 16)		

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

**SRC ENERGY INC.**  
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**  
(unaudited)

**1. Organization and Summary of Significant Accounting Policies**

**Organization:** SRC Energy Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids ("NGLs"), primarily in the Denver-Julesburg Basin ("D-J Basin") of Colorado. The Company's common stock is listed and traded on the NYSE American under the symbol "SRCL."

**Basis of Presentation:** The Company operates in one business segment, and all of its operations are located in the United States of America.

At the directive of the Securities and Exchange Commission ("SEC") to use "plain English" in public filings, the Company will use such terms as "we," "our," "us," or the "Company" in place of SRC Energy Inc. When such terms are used in this manner throughout this document, they are in reference only to the corporation, SRC Energy Inc., and are not used in reference to the Board of Directors, corporate officers, management, or any individual employee or group of employees.

The condensed consolidated financial statements include the accounts of the Company, including its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. The Company prepares its condensed consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("US GAAP").

**Interim Financial Information:** The unaudited condensed consolidated interim financial statements included herein have been prepared by the Company pursuant to the rules and regulations of the SEC as promulgated in Rule 10-01 of Regulation S-X. The condensed consolidated balance sheet as of December 31, 2017 was derived from the Company's annual consolidated financial statements included within its Annual Report on Form 10-K for the year ended December 31, 2017 as filed with the SEC on February 21, 2018. Accordingly, certain information and footnote disclosures normally included in financial statements prepared in accordance with US GAAP have been condensed or omitted pursuant to such SEC rules and regulations. The Company believes that the disclosures included are adequate to make the information presented not misleading and recommends that these condensed financial statements be read in conjunction with the audited financial statements and notes thereto for the year ended December 31, 2017.

In our opinion, the unaudited condensed consolidated financial statements contained herein reflect all adjustments, consisting solely of normal recurring items, which are necessary for the fair presentation of the Company's financial position, results of operations, and cash flows on a basis consistent with that of its prior audited financial statements. However, the results of operations for interim periods may not be indicative of results to be expected for the full fiscal year.

**Major Customers:** The Company sells production to a small number of customers as is customary in the industry. Customers representing 10% or more of our oil, natural gas, and NGL revenues ("major customers") for each of the periods presented are shown in the following table:

Major Customers	Three Months Ended March 31,	
	2018	2017
Company A	31%	23%
Company B	19%	22%
Company C	17%	31%
Company D	13%	*

\* less than 10%

Based on the current demand for oil and natural gas, the availability of other buyers, the multiple contracts for sales of our products, and the Company having the option to sell to other buyers if conditions warrant, the Company believes that the loss of our existing customers or individual contracts would not have a material adverse effect on us. Our oil and natural gas production is a commodity with a readily available market, and we sell our products under many distinct contracts. In addition, there are several oil and natural gas purchasers and processors within our area of operations to whom our production could be sold.

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Accounts receivable consist primarily of receivables from oil, natural gas, and NGL sales and amounts due from other working interest owners who are liable for their proportionate share of well costs. The Company typically has the right to withhold future revenue disbursements to recover outstanding joint interest billings on outstanding receivables from joint interest owners.

Customers with balances greater than 10% of total receivable balances as of each of the periods presented are shown in the following table (these companies do not necessarily correspond to those presented above):

Major Customers	As of	As of
	March 31, 2018	December 31, 2017
Company A	22%	16%
Company B	21%	26%
Company C	15%	23%
Company D	*	11%
* less than 10%		

The Company operates exclusively within the United States of America, and except for cash and cash equivalents, all of the Company's assets are utilized in, and all of our revenues are derived from, the oil and gas industry.

**Recently Adopted Accounting Pronouncements:**

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2014-09, "Revenue from Contracts with Customers (Topic 606)" ("ASU 2014-09"), which establishes a comprehensive new revenue recognition standard designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In March 2016, the FASB released certain implementation guidance through ASU 2016-08 (collectively with ASU 2014-09, the "Revenue ASUs") to clarify principal versus agent considerations. The Revenue ASUs allow for the use of either the full or modified retrospective transition method, and the standard will be effective for annual reporting periods beginning after December 15, 2017 including interim periods within that period, with early adoption permitted for annual reporting periods beginning after December 15, 2016. The Company adopted the guidance using the modified retrospective method with the effective date of January 1, 2018. The Company did not record a cumulative-effect adjustment to the opening balance of retained earnings as no adjustment was necessary. The adoption of the Revenue ASUs did not impact net income or cash flows. See Note 14 for the new disclosures required by the Revenue ASUs.

**Recently Issued Accounting Pronouncements:** We evaluate the pronouncements of various authoritative accounting organizations to determine the impact of new accounting pronouncements on us.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)" ("ASU 2016-02"), which establishes a comprehensive new lease standard designed to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. An entity that elects to apply the practical expedients will, in effect, continue to account for leases that commence before the effective date in accordance with previous US GAAP. ASU 2016-02 is effective for public businesses for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. We are currently evaluating the impact of the adoption of this standard on our financial statements.

There were various updates recently issued by the FASB, most of which represented technical corrections to the accounting literature or application to specific industries and are not expected to have a material impact on our reported financial position, results of operations, or cash flows.

**Change in estimates:** During the three months ended March 31, 2017, the Company adjusted its estimate for production taxes based on recent historical experience and additional information received during the periods. During the three months ended March 31, 2017, the Company decreased the accrual for production taxes to be paid by approximately \$2.0 million. This increased our operating income by a corresponding amount, or \$0.01 per basic and diluted common share.



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**2. Property and Equipment**

The capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	As of March 31, 2018	As of December 31, 2017
Oil and gas properties, full cost method:		
Costs of proved properties:		
Producing and non-producing	\$ 1,717,432	\$ 1,629,789
Less, accumulated depletion and full cost ceiling impairments	(695,707)	(659,205)
Subtotal, proved properties, net	1,021,725	970,584
Costs of wells in progress	149,214	106,269
Costs of unproved properties and land, not subject to depletion:		
Lease acquisition and other costs	788,798	786,469
Land	7,427	7,200
Subtotal, unproved properties and land	796,225	793,669
Costs of other property and equipment:		
Other property and equipment	8,484	8,134
Less, accumulated depreciation	(2,539)	(2,080)
Subtotal, other property and equipment, net	5,945	6,054
Total property and equipment, net	\$ 1,973,109	\$ 1,876,576

The Company periodically reviews its oil and gas properties to determine if the carrying value of such assets exceeds estimated fair value. For proved producing and non-producing properties, the Company performs a ceiling test each quarter to determine whether there has been an impairment to its capitalized costs. At March 31, 2018 and 2017, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairments were necessary.

**Capitalized Overhead:** A portion of the Company's overhead expenditures are directly attributable to acquisition, exploration, and development activities. Under the full cost method of accounting, these expenditures, in the amounts shown in the table below, were capitalized in the full cost pool (in thousands):

	Three Months Ended March 31,	
	2018	2017
Capitalized overhead	\$ 3,113	\$ 2,680

**3. Acquisitions, Swaps, and Divestitures**

*Acquisitions and Swaps*

*December 2017 Acquisition*

In December 2017, the Company completed the purchase of a total of approximately 30,200 net acres and the associated non-operated production in the Greeley-Crescent development area in Weld County Colorado, primarily south of the city of Greeley, for \$577.5 million, comprised of \$576.3 million in cash and the assumption of certain liabilities ("GCII Acquisition"). The purchase price has preliminarily been allocated as \$60.8 million to proved oil and gas properties and \$516.7 million to unproved oil and gas properties, pending the final closing. The effective date of this part of the transaction was November 1, 2017. The agreement also contemplates a second closing at which we will acquire operated producing properties subject to certain regulatory restrictions. The purchase price payable at the second closing will be determined based on the amount of then-current production from the properties conveyed and is expected to be completed in the second half of 2018. For the second closing, the effective date will be the first day of the calendar month in which the closing for such properties occurs. The second closing is subject to

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certain closing conditions including the receipt of regulatory approval. Accordingly, the second closing of the transaction may not occur in the expected time frame or at all.

The first closing was accounted for as an asset acquisition under ASC 805, *Business Combinations*, which requires the acquired assets and liabilities to be recorded at cost on the acquisition date of December 15, 2017.

#### *September 2017 Acquisition*

In September 2017, we completed the second closing contemplated by the May 2016 purchase and sale agreement pursuant to which we agreed to acquire a total of approximately 33,100 net acres in the Greeley-Crescent area for \$505 million (the "GC Acquisition"). The assets acquired at the second closing were comprised of 335 operated vertical wells and 7 operated horizontal wells. The effective date of the second closing was April 1, 2016 for the horizontal wells acquired and September 1, 2017 for the vertical wells acquired. At the second closing, the escrow balance of \$18.2 million was released and \$11.4 million of that amount was returned to the Company. The total purchase price for the assets acquired at the second closing was \$30.3 million, composed of cash of \$6.3 million and assumed liabilities of \$24.0 million. The assumed liabilities included \$20.9 million for asset retirement obligations. The entire purchase price has been allocated to proved oil and gas properties.

#### *August 2017 Acquisition and Swap*

In August 2017, we entered into an agreement with another party to trade approximately 3,200 net acres of the Company's non-contiguous acreage for approximately 3,200 net acres within the Company's core operating area. This transaction closed in the fourth quarter of 2017. Also in August 2017, we acquired approximately 1,000 net acres of developed and undeveloped leasehold and mineral interests, along with the associated production, for a total purchase price of \$22.6 million, composed of cash and assumed liabilities. The purchase price for the acquisition has preliminarily been allocated as \$6.7 million to proved oil and gas properties and \$15.9 million to unproved oil and gas properties, pending the final closing.

#### *March 2017 Acquisition*

In March 2017, we closed an acquisition comprised primarily of developed and undeveloped oil and gas leasehold interests for a total purchase price of \$25.1 million, composed of cash and assumed liabilities. The purchase price has been allocated as \$15.3 million to proved oil and gas properties, \$9.4 million to unproved oil and gas properties, and \$0.4 million to other assets and land.

#### *Divestitures*

During the year ended December 31, 2017, we completed divestitures of approximately 16,000 net undeveloped acres, along with associated production, outside of the Company's core development area for approximately \$91.6 million in cash and the assumption by the buyers of \$5.2 million in asset retirement obligations and \$22.2 million in other liabilities.

#### **4. Depletion, depreciation, and accretion ("DD&A")**

DD&A consisted of the following (in thousands):

	Three Months Ended March 31,	
	2018	2017
Depletion of oil and gas properties	\$ 36,102	\$ 12,703
Depreciation and accretion	979	526
Total DD&A Expense	\$ 37,081	\$ 13,229

Capitalized costs of proved oil and gas properties are depleted quarterly using the units-of-production method based on a depletion rate, which is calculated by comparing production volumes for the quarter to estimated total reserves at the beginning of the quarter. For the three months ended March 31, 2018, production of 4,086 MBOE represented 1.7% of estimated total proved reserves. For the three months ended March 31, 2017, production of 1,597 MBOE represented 1.1% of estimated total proved reserves. DD&A expense was \$9.08 per BOE and \$8.28 per BOE for the three months ended March 31, 2018 and 2017, respectively.

## 5. Asset Retirement Obligations

Upon completion or acquisition of a well, the Company recognizes obligations for its oil and natural gas operations for anticipated costs to remove and dispose of surface equipment, plug and abandon the wells, and restore the drilling site to its original use. The estimated present value of such obligations is determined using several assumptions and judgments about the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in regulations. Changes in estimates are reflected in the obligations as they occur. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the capitalized asset retirement cost. The following table summarizes the changes in asset retirement obligations associated with the Company's oil and gas properties (in thousands):

	Three Months Ended March 31, 2018
Asset retirement obligations, December 31, 2017	\$ 31,622
Obligations incurred with development activities	223
Obligations assumed with acquisitions	5
Accretion expense	520
Obligations discharged with asset retirements and divestitures	(2,860)
Asset retirement obligation, March 31, 2018	\$ 29,510
Less, current portion	(4,180)
Long-term portion	\$ 25,330

## 6. Revolving Credit Facility

The Company maintains a revolving credit facility (sometimes referred to as the "Revolver") with a bank syndicate with a maturity date of April 2, 2023. The Revolver is available for working capital for exploration and production operations, acquisitions of oil and gas properties, general corporate purposes, and to support letters of credit. At March 31, 2018, the terms of the Revolver provided for up to \$500 million in borrowings, subject to a borrowing base limitation of \$400 million. As of March 31, 2018 and December 31, 2017, there was no outstanding principal balance. At March 31, 2018, the Company had an outstanding letter of credit of approximately \$0.5 million.

On April 2, 2018, the Company entered into a second amended and restated credit agreement (the "Restated Credit Agreement") with certain banks and other lenders. The Restated Credit Agreement provides for a maximum credit amount of \$1.5 billion, an aggregate elected commitment of \$450 million, and a borrowing base of \$550 million. The Company is currently allowed to borrow up to \$450 million under the Restated Credit Agreement, less any outstanding amounts. In addition, the Restated Credit Agreement extends the maturity date of the facility from December 2019 to April 2023, reflects certain reductions in interest rates applicable to borrowings under the facility, and adds a \$25 million swingline facility. The next semi-annual redetermination is scheduled for November 2018.

Interest under the Revolver accrues monthly at a variable rate. For each borrowing, the Company designates its choice of reference rates, which can be either the Prime Rate plus a margin or LIBOR plus a margin. The interest rate margin, as well as other bank fees, varies with utilization of the Revolver. The average annual interest rate for borrowings during the three months ended March 31, 2017 was 2.8%.

Certain of the Company's assets, including substantially all of its producing wells and developed oil and gas leases, have been designated as collateral under the Restated Credit Agreement. The amount available to be borrowed is subject to scheduled redeterminations on a semi-annual basis. If certain events occur or if the bank syndicate or the Company so elects in certain circumstances, an unscheduled redetermination could be undertaken.

The Restated Credit Agreement contains covenants that, among other things, restrict the payment of dividends and limit our overall commodity derivative position to a maximum position that varies over 5 years as a percentage of estimated proved developed producing or total proved reserves as projected in the semi-annual reserve report.

Furthermore, the Restated Credit Agreement requires the Company to maintain compliance with certain financial and liquidity ratio covenants. In particular, the Company must not (a) permit its ratio of total funded debt to EBITDAX, as defined in the agreement, to be greater than or equal to 4.0 to 1.0 as of the last day of any fiscal quarter; or (b) permit its ratio of current assets to current liabilities, each as defined in the agreement, to be less than 1.0 to 1.0 as of the last day of any fiscal quarter. As

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of March 31, 2018, the most recent compliance date, the Company was in compliance with these loan covenants and expects to remain in compliance throughout the next 12-month period.

## **7. Notes Payable**

### ***2025 Senior Notes***

In November 2017, the Company issued \$550 million aggregate principal amount of 6.25% Senior Notes (the "2025 Senior Notes") in a private placement to qualified institutional buyers. The maturity for the payment of principal is December 1, 2025. Interest on the 2025 Senior Notes accrues at 6.25% and began accruing on November 29, 2017. Interest is payable on June 1 and December 1 of each year, beginning on June 1, 2018. The 2025 Senior Notes were issued pursuant to an indenture dated as of November 29, 2017 and are guaranteed on a senior unsecured basis by the Company's existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under the Revolver. The net proceeds from the sale of the 2025 Senior Notes were \$538.1 million after deductions of \$11.9 million for expenses and underwriting discounts and commissions. The associated expenses and underwriting discounts and commissions are amortized using the interest method at an effective interest rate of 6.6%. The net proceeds were used to fund the GCH Acquisition as discussed further in Note 3, to repay the 2021 Senior Notes, and to pay off the outstanding Revolver balance.

At any time prior to December 1, 2020, the Company may redeem all or a part of the 2025 Senior Notes at a redemption price equal to 100% of the principal amount plus an Applicable Premium (as defined in the Indenture) and accrued and unpaid interest. On and after December 1, 2020, the Company may redeem all or a part of the 2025 Senior Notes at a redemption price equal to a specified percentage of the principal amount of the redeemed notes (104.688% for 2020, 103.125% for 2021, 101.563% for 2022, and 100% for 2023 and thereafter, during the twelve-month period beginning on December 1 of each applicable year), plus accrued and unpaid interest. Additionally, prior to December 1, 2020, the Company can, on one or more occasions, redeem up to 35% of the principal amount of the 2025 Senior Notes with all or a portion of the net cash proceeds of one or more Equity Offerings (as defined in the Indenture) at a redemption price equal to 106.25% of the principal amount of the redeemed notes, plus accrued and unpaid interest, subject to certain conditions.

The Indenture contains covenants that restrict the Company's ability and the ability of certain of its subsidiaries to, among other restrictions and limitations: (i) incur additional indebtedness; (ii) incur liens; (iii) pay dividends; (iv) consolidate, merge, or transfer all or substantially all of its or their assets; (v) engage in transactions with affiliates; or (vi) engage in certain restricted business activities. These covenants are subject to a number of exceptions and qualifications.

As of March 31, 2018, the most recent compliance date, the Company was in compliance with these covenants and expects to remain in compliance throughout the next 12-month period.

## **8. Commodity Derivative Instruments**

The Company has entered into commodity derivative instruments as described below. Our commodity derivative instruments may include but are not limited to "collars," "swaps," and "put" positions. Our derivative strategy, including the volumes and commodities covered and the relevant strike prices, is based in part on our view of expected future market conditions and our analysis of well-level economic return potential. In addition, our use of derivative contracts is subject to stipulations set forth in the Revolver.

The Company may, from time to time, add incremental derivatives to cover additional production, restructure existing derivative contracts, or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with five counterparties and an exchange. Three of the counterparties are lenders in the Revolver. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

The Company's commodity derivative instruments are measured at fair value and are included in the accompanying condensed consolidated balance sheets as commodity derivative assets or liabilities. Unrealized gains and losses are recorded based on the changes in the fair values of the derivative instruments. Both the unrealized and realized gains and losses are recorded in the condensed consolidated statements of operations. The Company's cash flow is only impacted when the actual settlements

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under commodity derivative contracts result in it making or receiving a payment to or from the counterparty. Actual cash settlements can occur at either the scheduled maturity date of the contract or at an earlier date if the contract is liquidated prior to its scheduled maturity. These settlements under the commodity derivative contracts are reflected as operating activities in the Company's condensed consolidated statements of cash flows.

The Company's commodity derivative contracts as of March 31, 2018 are summarized below:

Settlement Period	Derivative Instrument	Volumes (Bbls per day)	Weighted-Average Floor Price	Weighted-Average Ceiling Price
<b>Crude Oil - NYMEX WTI</b>				
Apr 1, 2018 - Dec 31, 2018	Collar	10,000	\$ 43.63	\$ 61.29
Settlement Period	Derivative Instrument	Volumes (MMBtu per day)	Weighted-Average Floor Price	Weighted-Average Ceiling Price
<b>Natural Gas - CIG Rocky Mountain</b>				
Apr 1, 2018 - Dec 31, 2018	Collar	15,000	\$ 2.25	\$ 2.82
Settlement Period	Derivative Instrument	Volumes (Bbls per day)	Fixed Price	
<b>Propane - Mont Belvieu</b>				
Apr 1, 2018 - Dec 31, 2018	Swap	1,000	\$ 33.60	

*Offsetting of Derivative Assets and Liabilities*

As of March 31, 2018 and December 31, 2017, all derivative instruments held by the Company were subject to enforceable master netting arrangements held by various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of either party, for transactions that occur on the same date and in the same currency. The Company's agreements also provide that, in the event of an early termination, each party has the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to offset these positions in its condensed consolidated balance sheets.

The following table provides a reconciliation between the net assets and liabilities reflected on the accompanying condensed consolidated balance sheets and the potential effect of master netting arrangements on the fair value of the Company's derivative contracts (in thousands):

Underlying	Balance Sheet Location	As of March 31, 2018		
		Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets and Liabilities Presented in the Balance Sheet
Commodity derivative contracts	Current assets	\$ 1,828	\$ (1,828)	\$ —
Commodity derivative contracts	Noncurrent assets	\$ —	\$ —	\$ —
Commodity derivative contracts	Current liabilities	\$ 13,402	\$ (1,828)	\$ 11,574
Commodity derivative contracts	Noncurrent liabilities	\$ —	\$ —	\$ —
Underlying	Balance Sheet Location	As of December 31, 2017		
		Gross Amounts of Recognized Assets and Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets and Liabilities Presented in the Balance Sheet
Commodity derivative contracts	Current assets	\$ 1,960	\$ (1,960)	\$ —
Commodity derivative contracts	Noncurrent assets	\$ —	\$ —	\$ —
Commodity derivative contracts	Current liabilities	\$ 9,825	\$ (1,960)	\$ 7,865
Commodity derivative contracts	Noncurrent liabilities	\$ —	\$ —	\$ —

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The amount of gain (loss) recognized in the condensed consolidated statements of operations related to derivative financial instruments was as follows (in thousands):

	Three Months Ended March 31,	
	2018	2017
Realized loss on commodity derivatives	\$ (2,072)	\$ (119)
Unrealized gain (loss) on commodity derivatives	(3,709)	3,498
Total gain (loss)	\$ (5,781)	\$ 3,379

Realized gains and losses include cash received from the monthly settlement of derivative contracts at their scheduled maturity date net of the previously incurred premiums attributable to settled commodity contracts. The following table summarizes derivative realized gains and losses during the periods presented (in thousands):

	Three Months Ended March 31,	
	2018	2017
Monthly settlement	\$ (2,072)	\$ 225
Previously incurred premiums attributable to settled commodity contracts	—	(344)
Total realized loss	\$ (2,072)	\$ (119)

#### *Credit Related Contingent Features*

As of March 31, 2018, three of the six counterparties to the Company's derivative instruments were members of the Company's credit facility syndicate. The Company's obligations under the credit facility and its derivative contracts are secured by liens on substantially all of the Company's producing oil and gas properties. The agreement with the fourth and fifth counterparties, which are not lenders under the credit facility, is unsecured and does not require the posting of collateral. The agreement with the sixth counterparty, which is not a lender under the credit facility, may require the posting of collateral if in a liability position.

#### **9. Fair Value Measurements**

ASC 820, *Fair Value Measurements and Disclosure*, establishes a hierarchy for inputs used in measuring fair value for financial assets and liabilities that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; and
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash or valuation models.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The Company's non-recurring fair value measurements include unproved properties, asset retirement obligations, and purchase price allocations for the fair value of assets and liabilities acquired through certain asset acquisitions. Please refer to Notes 2, 3, and 5 for further discussion of unproved properties, asset acquisitions, and asset retirement obligations, respectively.

The acquisition of a group of assets in certain asset acquisitions requires fair value estimates for assets acquired and liabilities assumed. The fair value of assets and liabilities acquired is calculated using a net discounted cash flow approach for the proved producing, proved undeveloped, probable, and possible properties. The discounted cash flows are developed using the income approach and are based on management's expectations for the future. Unobservable inputs include estimates of future

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oil and natural gas production from the Company's reserve reports, commodity prices based on the NYMEX forward price curves as of the date of the estimate (adjusted for basis differentials), estimated operating and development costs, and a risk-adjusted discount rate (all of which are designated as Level 3 inputs within the fair value hierarchy). For unproved properties, the fair value is determined using market comparables.

The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using Level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit-adjusted risk-free rate, inflation rates, and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period, and the capitalized asset retirement cost is depleted as a component of the full cost pool using the units-of-production method. See Notes 3 and 5 for additional information.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis by level within the fair value hierarchy (in thousands):

	Fair Value Measurements at March 31, 2018			
	Level 1	Level 2	Level 3	Total
<b>Financial assets and liabilities:</b>				
Commodity derivative asset	\$ —	\$ —	\$ —	\$ —
Commodity derivative liability	\$ —	\$ 11,574	\$ —	\$ 11,574
	Fair Value Measurements at December 31, 2017			
	Level 1	Level 2	Level 3	Total
<b>Financial assets and liabilities:</b>				
Commodity derivative asset	\$ —	\$ —	\$ —	\$ —
Commodity derivative liability	\$ —	\$ 7,865	\$ —	\$ 7,865

#### *Commodity Derivative Instruments*

The Company determines its estimate of the fair value of commodity derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, the credit rating of each counterparty, and the Company's own credit standing. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparties to its derivative contracts would default by failing to make any contractually required payments. The Company considers the counterparties to be of substantial credit quality and believes that they have the financial resources and willingness to meet their potential repayment obligations associated with the derivative transactions. At March 31, 2018, derivative instruments utilized by the Company consist of swaps and collars. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are based on several factors including public indices, the instruments themselves are traded with third-party counterparties. As such, the Company has classified these instruments as Level 2.

#### *Fair Value of Financial Instruments*

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above), notes payable, and credit facility borrowings. The carrying values of cash and cash equivalents, cash held in escrow, accounts receivable, and accounts payable are representative of their fair values due to their short-term maturities. Due to the variable interest rate paid on the credit facility borrowings, the carrying value is representative of its fair value.

The fair value of the notes payable is estimated to be \$509.9 million at March 31, 2018. The Company determined the fair value of its notes payable at March 31, 2018 by using observable market based information for debt instruments of similar amounts and duration. The Company has classified the notes payable as Level 2.

[Table of Contents](#)**10. Interest Expense**

The components of interest expense are (in thousands):

	Three Months Ended March 31,	
	2018	2017
Revolving bank credit facility	\$ —	\$ 43
Notes payable	8,594	1,800
Amortization of issuance costs and other	887	500
Less: interest capitalized	(9,481)	(2,343)
Interest expense, net of amounts capitalized	\$ —	\$ —

**11. Stock-Based Compensation**

In addition to cash compensation, the Company may compensate employees and directors with equity-based compensation in the form of stock options, performance-vested stock units, restricted stock units, stock bonus shares, and other equity awards. The Company records its equity compensation by pro-rating the estimated grant-date fair value of each grant over the period of time that the recipient is required to provide services to the Company (the "vesting period"). The calculation of fair value is based, either directly or indirectly, on the quoted market value of the Company's common stock. Indirect valuations are calculated using the Black-Scholes-Merton option pricing model or a Monte Carlo Model. For the periods presented, all stock-based compensation was either classified as a component within general and administrative expense in the Company's condensed consolidated statements of operations or, for that portion which is directly attributable to individuals performing acquisition, exploration, and development activities, was capitalized to the full cost pool. As of March 31, 2018, there were 4,500,000 common shares authorized for grant under the 2015 Equity Incentive Plan, of which 6,217,650 shares had been granted. The shares granted include 1,555,263 shares which have been reserved for future vesting of performance-vested stock units under the assumption that these awards met the criterion to vest at their maximum multiplier. At the Company's annual meeting of shareholders on May 18, 2018, the Company will request approval to increase the common shares authorized for grant under the 2015 Equity Incentive Plan to 10,500,000. In the event that this approval is not received, the grants exceeding the presently approved limit will be settled with cash.

The amount of stock-based compensation was as follows (in thousands):

	Three Months Ended March 31,	
	2018	2017
Stock options	\$ 1,203	\$ 1,246
Performance-vested stock units	856	525
Restricted stock units and stock bonus shares	1,336	1,346
Total stock-based compensation	\$ 3,395	\$ 3,117
Less: stock-based compensation capitalized	(599)	(442)
Total stock-based compensation expensed	\$ 2,796	\$ 2,675



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*Stock options*

No stock options were granted during the three months ended March 31, 2018 or 2017. The following table summarizes activity for stock options for the periods presented:

	Number of Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Aggregate Intrinsic Value (thousands)
Outstanding, December 31, 2017	5,636,834	\$ 9.38	7.0 years	\$ 4,806
Granted	—	—		
Exercised	(277,600)	4.07		1,490
Expired	(23,400)	11.27		
Forfeited	(30,000)	11.57		
Outstanding, March 31, 2018	5,305,834	\$ 9.64	7.0 years	\$ 5,158
Outstanding, Exercisable at March 31, 2018	3,076,213	\$ 9.48	6.6 years	\$ 3,443

The following table summarizes information about issued and outstanding stock options as of March 31, 2018:

Range of Exercise Prices	Outstanding Options			Exercisable Options		
	Options	Weighted-Average Exercise Price per Share	Weighted-Average Remaining Contractual Life	Options	Weighted-Average Exercise Price per Share	Weighted-Average Remaining Contractual Life
Under \$5.00	195,000	\$ 2.97	3.8 years	195,000	\$ 2.97	3.8 years
\$5.00 - \$6.99	1,005,000	6.38	6.7 years	601,400	6.40	5.6 years
\$7.00 - \$10.99	1,533,834	9.36	7.2 years	789,413	9.43	6.9 years
\$11.00 - \$13.46	2,572,000	11.58	7.2 years	1,490,400	11.60	7.1 years
Total	5,305,834	\$ 9.64	7.0 years	3,076,213	\$ 9.48	6.6 years

The estimated unrecognized compensation cost from stock options not vested as of March 31, 2018, which will be recognized ratably over the remaining vesting phase, is as follows:

Unrecognized compensation cost (in thousands)	\$ 8,308
Remaining vesting phase	2.1 years

*Restricted stock units and stock bonus awards*

The Company grants restricted stock units and stock bonus awards to directors, eligible employees, and officers as a part of its equity incentive plan. Restrictions and vesting periods for the awards are determined by the Compensation Committee of the Board of Directors and are set forth in the award agreements. Each restricted stock unit or stock bonus award represents one share of the Company's common stock to be released from restrictions upon completion of the vesting period. The awards typically vest in equal increments over three to five years. Restricted stock units and stock bonus awards are valued at the closing price of the Company's common stock on the grant date and are recognized over the vesting period of the award.

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The following table summarizes activity for restricted stock units and stock bonus awards for the three months ended March 31, 2018:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Not vested, December 31, 2017	1,087,386	\$ 8.89
Granted	639,752	9.12
Vested	(276,973)	8.17
Forfeited	(30,302)	10.16
Not vested, March 31, 2018	1,419,863	\$ 9.11

The estimated unrecognized compensation cost from restricted stock units and stock bonus awards not vested as of March 31, 2018, which will be recognized ratably over the remaining vesting phase, is as follows:

Unrecognized compensation cost (in thousands)	\$ 11,304
Remaining vesting phase	2.4 years

*Performance-vested stock units*

The Company grants two types of performance-vested stock units ("PSUs") to certain executives under its long-term incentive plan. The number of shares of the Company's common stock that may be issued to settle PSUs ranges from zero to two times the number of PSUs awarded. The shares issued for PSUs are determined based on the Company's performance over a three-year measurement period and vest in their entirety at the end of the measurement period. The PSUs will be settled in shares of the Company's common stock following the end of the three-year performance cycle. Any PSUs that have not vested at the end of the applicable measurement period are forfeited.

*Total Shareholder Return ("TSR") PSUs* - The vesting criterion for the TSR PSUs is based on a comparison of the Company's TSR for the measurement period compared with the TSRs of a group of peer companies for the same measurement period. As the vesting criterion is linked to the Company's share price, it is considered a market condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the TSR PSUs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's TSR PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the TSR PSUs. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period, and the volatilities for each of the Company's peers.

The assumptions used in valuing the TSR PSUs granted were as follows:

	Three Months Ended March 31,	
	2018	2017
Weighted-average expected term	2.8 years	2.9 years
Weighted-average expected volatility	52%	59%
Weighted-average risk-free rate	2.41%	1.34%

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The fair value of the TSR PSUs granted during the three months ended March 31, 2018 and 2017 was \$4.2 million and \$5.1 million, respectively. As of March 31, 2018, unrecognized compensation cost for TSR PSUs was \$8.4 million and will be amortized through 2020. A summary of the status and activity of TSR PSUs is presented in the following table:

	Number of Units <sup>1</sup>	Weighted-Average Grant-Date Fair Value
Not vested, December 31, 2017	951,884	\$ 9.44
Granted	321,507	13.11
Vested	—	—
Forfeited	—	—
Not vested, March 31, 2018	<u>1,273,391</u>	<u>\$ 10.36</u>

<sup>1</sup> The number of awards assumes that the associated vesting condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the vesting condition.

*Corporate Goals PSUs* - The Corporate Goals PSUs have not been finalized by the Compensation Committee, and we have not yet met the requirements of establishing an accounting grant date for them. This will occur when we communicate the terms of the awards to the award recipients, which will then trigger the service inception date, the fair value of the awards, and the associated expense recognition period. As of March 31, 2018, 281,872 Corporate Goals PSUs had been awarded to certain executives.

**12. Weighted-Average Shares Outstanding**

The following table sets forth the Company's outstanding equity grants which have a dilutive effect on earnings per share:

	Three Months Ended March 31,	
	2018	2017
Weighted-average shares outstanding — basic	241,751,915	200,707,891
Potentially dilutive common shares from:		
Stock options	347,391	461,103
TSR PSUs <sup>1</sup>	810,128	—
Restricted stock units and stock bonus shares	257,463	140,257
Weighted-average shares outstanding — diluted	<u>243,166,897</u>	<u>201,309,251</u>

<sup>1</sup> The number of awards assumes that the associated vesting condition is met at the respective period end based on market prices as of the respective period end. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the vesting condition.

The following potentially dilutive securities outstanding for the periods presented were not included in the respective weighted-average shares outstanding-diluted calculation above:

	Three Months Ended March 31,	
	2018	2017
Potentially dilutive common shares from:		
Stock options <sup>1</sup>	4,127,834	4,722,500
TSR PSUs <sup>1,2</sup>	—	951,884
Corporate Goals PSUs <sup>2,3</sup>	281,872	—
Restricted stock units and stock bonus shares <sup>1</sup>	398,561	605,252
Total	<u>4,808,267</u>	<u>6,279,636</u>

<sup>1</sup> Potential common shares excluded from weighted-average shares outstanding-diluted calculation as the securities had an anti-dilutive effect on earnings per share.

<sup>2</sup> The number of awards reflects the target amount of shares granted. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the vesting condition.

<sup>3</sup> Potential common shares excluded from weighted-average shares outstanding-diluted calculation as the securities are considered contingently issuable, and the performance criteria are not considered met as of period end.

### 13. Income Taxes

We evaluate and update our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating results and tax laws. Consequently, based upon the mix and timing of our actual earnings compared to annual projections, our effective tax rate may vary quarterly and may make quarterly comparisons not meaningful. The quarterly income tax provision is generally comprised of tax expense on income or benefit on loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

During the three months ended March 31, 2018, the Company concluded it is more likely than not it will realize the benefits of its net deferred tax assets by the end of 2018 as a result of current year ordinary income. This conclusion was based upon the Company's projection of cumulative positive net income for the three-year period ended December 31, 2018. The release of the valuation allowance is reflected in the Company's estimated annual effective tax rate since the realization of the Company's deferred tax assets is supported by current year ordinary income. The Company is projecting a net deferred tax liability with a full release of its beginning valuation allowance by the end of 2018.

The effective tax rates for the three months ended March 31, 2018 and 2017 were 8% and nil, respectively. The effective tax rates for the three months ended March 31, 2018 and 2017 differed from the statutory rates due primarily to the release of valuation allowances previously recorded against deferred tax assets.

As of March 31, 2018, we had no liability for unrecognized tax benefits. The Company believes that there are no new items nor changes in facts or judgments that should impact the Company's tax position. Given the substantial NOL carryforwards at both the federal and state levels, it is anticipated that any changes resulting from a tax examination would simply adjust the carryforwards and would not result in significant interest expense or penalties. Most of the Company's tax returns filed since August 31, 2011 are still subject to examination by tax authorities. As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions, and we are not currently under any state income tax examinations.

No significant uncertain tax positions were identified as of any date on or before March 31, 2018. The Company's policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of March 31, 2018, the Company has not recognized any interest or penalties related to uncertain tax benefits.

Each period, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. As of March 31, 2018, the Company believes it will be able to generate sufficient future taxable income within the carryforward periods and, accordingly, believes that it is more likely than not that its net deferred income tax assets will be fully realized.

### 14. Revenue from Contracts with Customers

Sales of oil, natural gas, and NGLs are recognized at the point control of the product is transferred to the customer and collectability is reasonably assured. All of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies.

Revenues (in thousands):	Three Months Ended March 31,	
	2018	2017
Oil	\$ 116,204	\$ 29,149
Natural Gas and NGLs	31,029	14,641
	<u>\$ 147,233</u>	<u>\$ 43,790</u>

#### *Natural Gas and NGLs Sales*

Under our natural gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to us for the resulting sales of NGLs and residue gas. For these contracts, we have concluded the midstream processing entity is our customer. We recognize natural gas and NGLs revenues based on the net amount of the proceeds received from the midstream processing.

*Oil Sales*

Our oil sales contracts are generally structured in one of the following ways:

- We sell oil production at the wellhead and collect an agreed-upon index price, net of pricing differentials. In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead at the net price received.
- We deliver oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title, and risk of loss of the product. Under this arrangement, we pay a third party to transport the product and receive a specified index price from the purchaser, net of pricing differentials. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. The third-party costs are recorded as Transportation and gathering in our condensed consolidated statements of operations.

*Transaction Price Allocated to Remaining Performance Obligations*

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

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

*Contract Balances*

Under our product sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not typically give rise to contract assets or liabilities under ASC 606, and as of March 31, 2018, we did not have any material contract balances.

*Prior-Period Performance Obligations*

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain sales may not be received for 30 to 90 days after the date production is delivered, and 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, and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the three months ended March 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

## 15. Other Commitments and Contingencies

### *Volume Commitments*

The Company entered into firm sales agreements for its oil production with three counterparties during 2014 and entered into an additional firm sales agreement for its oil production in the third quarter 2017. Deliveries under two of the sales agreements commenced during 2015. Deliveries under the third agreement commenced in 2016. Deliveries under the fourth agreement are expected to commence in the fourth quarter of 2018. Pursuant to these agreements, we must deliver specific amounts of oil either from our own production or from oil that we acquire from third parties. If we are unable to fulfill all of our contractual obligations, we may be required to pay penalties or damages pursuant to these agreements. Our commitments over the next five years, excluding the contingent commitment described below, are as follows:

Year ending December 31,	Oil (MBbls)
Remainder of 2018	3,436
2019	5,167
2020	4,003
2021	1,672
2022	—
Thereafter	—
Total	14,278

During the first quarter of 2018, we were able to meet all of our delivery obligations, and we anticipate that our current gross operated production will continue to meet our future delivery obligations, although this cannot be guaranteed.

In collaboration with several other producers and DCP Midstream, LP ("DCP Midstream"), we have agreed to participate in the expansion of natural gas gathering and processing capacity in the D-J Basin. The first agreement includes a new 200 MMcf per day processing plant as well as the expansion of a related gathering system. Both are currently expected to be completed during the third quarter of 2018, although the start-up date is undetermined at this time. Our share of the commitment will require 46.4 MMcf per day to be delivered after the plant in-service date for a period of 7 years. The second agreement also includes a new 200 MMcf per day processing plant as well as the expansion of a related gathering system. Both are currently expected to be completed in 2019, although the start-up date is undetermined at this time. Our share of the commitment will require 43.8 MMcf per day to be delivered after the plant in-service date for a period of 7 years. These contractual obligations can be reduced by the collective volumes delivered to the plants by other producers in the D-J Basin that are in excess of such producers' total commitment. We expect that our development plan will support the utilization of this capacity.

### *Litigation*

From time to time, the Company is a party to various commercial and regulatory claims, pending or threatened legal action, and other proceedings that arise in the ordinary course of business. It is the opinion of management that none of the current proceedings are reasonably likely to have a material adverse impact on its business, financial position, results of operations, or cash flows.

### *Office leases*

In September 2016, the Company entered into a 65-month lease for the Company's principal office space located in Denver, which commenced in the first quarter of 2017. Rent under the lease is approximately \$62,000 per month. In July 2016, the Company entered into a field office lease in Greeley which requires monthly payments of \$7,500 through October 2021.

Rent expense for offices leases was \$0.3 million and \$0.4 million for the three months ended March 31, 2018 and 2017, respectively.

### *Vehicle Leases*

The Company has entered into a leasing arrangement for its vehicles used in our normal operations. These leases terminate after four years and are classified as capital leases. The assets associated with these capital leases are recorded within "Other property and equipment, net."

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A schedule of the minimum lease payments under non-cancelable capital and operating leases as of March 31, 2018 follows (in thousands):

Year ending December 31:	Vehicles Leases	Office Leases
Remainder of 2018	\$ 91	\$ 629
2019	94	896
2020	94	916
2021	120	913
2022	51	500
Thereafter	—	—
Total minimum lease payments	\$ 450	\$ 3,854
Less: Amount representing estimated executory cost	(37)	
Net minimum lease payments	413	
Less: Amount representing interest	(59)	
Present value of net minimum lease payments *	\$ 354	

\* Reflected in the balance sheet as current and non-current obligations of \$83 thousand and \$271 thousand, respectively, within "Accounts payable and accrued expenses" and "Other liabilities," respectively.

**16. Supplemental Schedule of Information to the Condensed Consolidated Statements of Cash Flows**

The following table supplements the cash flow information presented in the condensed consolidated financial statements for the periods presented (in thousands):

Supplemental cash flow information:	Three Months Ended March 31,	
	2018	2017
Interest paid	\$ 69	\$ 43
Income taxes paid	—	—
Non-cash investing and financing activities:		
Accrued well costs as of period end	\$ 66,823	\$ 81,722
Asset retirement obligations incurred with development activities	223	882
Asset retirement obligations assumed with acquisitions	5	1,098
Obligations discharged with asset retirements and divestitures	(2,860)	(3,287)
Net changes in operating assets and liabilities:		
Accounts receivable	(8,227)	(3,745)
Accounts payable and accrued expenses	4,420	5,293
Revenue payable	13,060	2,486
Production taxes payable	5,295	(4,807)
Other	(116)	(1,591)
Changes in operating assets and liabilities	14,432	(2,364)

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

The following discussion and analysis was prepared to supplement information contained in the accompanying condensed consolidated financial statements and is intended to explain certain items regarding the Company's financial condition as of March 31, 2018 and its results of operations for the three months ended March 31, 2018 and 2017. It should be read in conjunction with the "Selected Financial Data" and the accompanying audited consolidated financial statements and related notes thereto contained in the Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on February 21, 2018. Unless the context otherwise requires, references to "SRC Energy," "we," "us," "our," or the "Company" in this report refer to the registrant, SRC Energy Inc., and its subsidiaries.

This section and other parts of this Quarterly Report on Form 10-Q contain forward-looking statements that involve risks and uncertainties. See the "Cautionary Statement Concerning Forward-Looking Statements" elsewhere in this Quarterly Report on Form 10-Q. Forward-looking statements are not guarantees of future performance, and our actual results may differ significantly from the results discussed in the forward-looking statements. Factors that might cause such differences include, but are not limited to, those discussed in "Risk Factors." We assume no obligation to revise or update any forward-looking statements for any reason, except as required by law.

**Overview**

SRC Energy Inc. is an independent oil and gas company engaged in the acquisition, development, and production of oil, natural gas, and NGLs in the D-J Basin, which we believe to be one of the premier, liquids-rich oil and natural gas resource plays in the United States. It contains hydrocarbon-bearing deposits in several formations, including the Niobrara, Codell, Greenhorn, Shannon, Sussex, J-Sand, and D-Sand. The area has produced oil and natural gas for over fifty years and benefits from established infrastructure including midstream and refining capacity, long reserve life, and multiple service providers.

Our oil and natural gas activities are focused in the Wattenberg Field, predominantly in Weld County, Colorado, an area that covers the western flank of the D-J Basin. Currently, we are focused on the horizontal development of the Codell formation as well as the three benches of the Niobrara formation, which are all characterized by relatively high liquids content.

In order to maintain operational focus while preserving developmental flexibility, we strive to attain operational control of a majority of the wells in which we have a working interest. We currently operate approximately 80% of our proved producing reserves and anticipate operating substantially all of our future net drilling locations. Additionally, our current development plan anticipates that all of our future activities will be concentrated in the Wattenberg Field.

**Market Conditions**

Market prices for our products significantly impact our revenues, net income, and cash flow. The market prices for oil, natural gas, and NGLs are inherently volatile. To provide historical perspective, the following table presents the average annual NYMEX prices for oil and natural gas for each of the last five fiscal years.

	Year Ended December 31,			Year Ended August 31,		
	2017	2016	2015	2015	2014	2013
Average NYMEX prices						
Oil (per Bbl)	\$ 50.93	\$ 43.20	\$ 48.73	\$ 60.65	\$ 100.39	\$ 94.58
Natural gas (per Mcf)	\$ 3.00	\$ 2.52	\$ 2.58	\$ 3.12	\$ 4.38	\$ 3.55



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For the periods presented in this report, the following table presents the Reference Price (derived from average NYMEX prices) as well as the differential between the Reference Price and the prices realized by us.

	Three Months Ended March 31,	
	2018	2017
<b>Oil (NYMEX WTI)</b>		
Average NYMEX Price	\$ 62.89	\$ 51.91
Realized Price *	56.01	42.50
Differential *	\$ (6.88)	\$ (9.41)
<b>Gas (NYMEX Henry Hub)</b>		
Average NYMEX Price	\$ 3.00	\$ 3.01
Realized Price	2.14	2.66
Differential	\$ (0.86)	\$ (0.35)
NGL Realized Price	\$ 19.15	\$ 15.94

\* Adjusted to include the effect of transportation and gathering expenses.

Market conditions in the Wattenberg Field require us to sell oil at prices less than the prices posted by the NYMEX. The differential between the prices actually received by us at the wellhead and the published indices reflects deductions imposed upon us by the purchasers for location and quality adjustments. The Company's oil production exceeds its firm sales commitments, and the surplus oil production is sold at a reduced differential as compared to our committed volumes. With regard to the sale of oil during the first quarter of 2017, substantially all of the Company's oil production was sold to the counterparties of its firm sales commitments.

There has been significant volatility in the price of oil and natural gas since mid-2014. During the three months ended March 31, 2018, the NYMEX-WTI oil price ranged from a high of \$66.27 per Bbl on January 26, 2018 to a low of \$59.20 per Bbl on February 9, 2018, and the NYMEX-Henry Hub natural gas price ranged from a low of \$2.55 per MMBtu on February 12, 2018 to a high of \$3.63 per MMBtu on January 29, 2018. As reflected in published data, the price for WTI oil settled at \$60.46 per Bbl on December 29, 2017. Comparably, the price of oil settled at \$64.87 per Bbl on Friday, March 30, 2018, an increase of 7% from December 29, 2017. Our revenues, results of operations, profitability and future growth, and the carrying value of our oil and gas properties depend primarily on the prices that we receive for our oil, natural gas, and NGL production.

A decline in oil and natural gas prices will adversely affect our financial condition and results of operations. Furthermore, low oil and natural gas prices can result in an impairment of the value of our properties and impact the calculation of the "ceiling test" required under the accounting principles for companies following the "full cost" method of accounting. At March 31, 2018, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, if pricing conditions decline, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters.

**Core Operations**

The following table provides details about our ownership interests with respect to vertical and horizontal producing wells as of March 31, 2018:

Vertical Wells					
Operated Wells		Non-Operated Wells		Totals	
Gross	Net	Gross	Net	Gross	Net
296	285	163	48	459	333
Horizontal Wells					
Operated Wells		Non-Operated Wells		Totals	
Gross	Net	Gross	Net	Gross	Net
239	229	283	51	522	280

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In addition to the producing wells summarized in the preceding table, as of March 31, 2018, we were the operator of 67 gross (60 net) horizontal wells in progress, which excludes 23 gross (21 net) wells for which we have only set surface casings. As of March 31, 2018, we are participating in 37 gross (9 net) non-operated horizontal wells in progress.

As we develop our acreage through horizontal drilling, we have an active program for plugging and abandoning the vast majority of the operated vertical wellbores. During the three months ended March 31, 2018, we plugged 45 wells and returned the associated acreage to the property owners.

### **Production**

For the three months ended March 31, 2018, our average daily production increased to 45,397 BOED as compared to 17,743 BOED for the three months ended March 31, 2017. As of March 31, 2018, approximately 99% of our daily production was from horizontal wells.

### **Strategy**

Our primary objective is to enhance shareholder value by increasing our net asset value, net reserves, and cash flow through development, exploitation, exploration, and acquisitions of oil and gas properties. We intend to follow a balanced risk strategy by allocating capital expenditures to lower risk development and exploitation activities. Key elements of our business strategy include the following:

- *Concentrate on our existing core area in the D-J Basin, where we have significant operating experience.* All of our current wells and our proved undeveloped acreage are located either in or adjacent to the Wattenberg Field, and we seek to acquire developed and undeveloped oil and gas properties in the same area. Focusing our operations in this area leverages our management, technical, and operational experience in the basin.
- *Develop and exploit existing oil and gas properties.* Our principal growth strategy has been to develop and exploit our properties to add reserves. In the Wattenberg Field, we target three benches of the Niobrara formation as well as the Codell formation for horizontal drilling and production. We believe horizontal drilling is the most efficient way to recover the potential hydrocarbons and consider the Wattenberg Field to be relatively low-risk because information gained from the large number of existing wells can be applied to potential future wells. There is enough similarity between wells in the Wattenberg Field that the exploitation process is generally repeatable.
- *Use the latest technology to maximize returns and improve hydrocarbon recovery.* Our development objective for individual well optimization is to drill and complete wells with lateral lengths of 7,000' to 10,000'. Utilizing petrophysical and seismic data, a 3-D model is developed for each leasehold section to assist in determining optimal wellbore placement, well spacing, and stimulation design. This process is augmented with formation-specific drilling and completion execution designs and coupled with localized production results to implement a continuous improvement philosophy in optimizing the value per acre of our leasehold throughout our development program.
- *Operate in a safe manner and work in partnership with our surrounding stakeholders.* While our scale of operations has increased significantly, we continue to focus on maintaining a safe workplace for our employees and contractors. Further, as technology for resource development has advanced, we seek to utilize best industry practices to meet or exceed regulatory requirements while reducing our impacts on neighboring communities. We value our positive relationship with local governing entities and the communities in which we operate and seek to continually achieve a status of operator of choice.
- *Retain control over the operation of a substantial portion of our production.* As operator of a majority of our wells and undeveloped acreage, we control the timing and selection of new wells to be drilled. This allows us to modify our capital spending as our financial resources and underlying lease terms allow and market conditions permit.
- *Maintain financial flexibility while focusing on operational cost control.* We strive to be a cost-efficient operator and to maintain a relatively low utilization of debt, which enhances our financial flexibility. Our high degree of operational control, as well as our focus on operating efficiencies and short return on investment cycle times, is central to our operating strategy.
- *Acquire and develop assets near established infrastructure.* We have made acquisitions of contiguous acreage and aligned our development plans where technically-capable, financially-stable midstream companies have existing assets and plans

for additional investment. We work collaboratively with these companies to proactively identify expansion opportunities that complement our development plans while reducing truck traffic.

## **Significant Developments**

### ***Revolving Credit Facility***

On April 2, 2018, the Company entered into a second amended and restated credit agreement (the “Restated Credit Agreement”) with certain banks and other lenders, including SunTrust Bank, as administrative agent, swingline lender and issuing bank. Among other things, the Restated Credit Agreement, which amends and restates the Company’s prior credit agreement, provides for a maximum credit amount of \$1.5 billion, an elected commitment amount of \$450 million, and a borrowing base of \$550 million. The Company is currently allowed to borrow up to \$450 million under the Restated Credit Agreement, less any outstanding amounts. In addition, the Restated Credit Agreement extends the maturity date of the facility from December 2019 to April 2023, reflects certain reductions in interest rates applicable to borrowings under the facility, and adds a \$25 million swingline facility.

### **Drilling and Completion Operations**

Our drilling and completion schedule drives our production forecast and our expected future cash flows. We believe that at current drilling and completion cost levels and with currently prevailing commodity prices, we can achieve attractive well-level rates of return. Should commodity prices weaken or our costs escalate significantly, our operational flexibility will allow us to adjust our drilling and completion schedule, if prudent. If the well-level internal rate of return is at or below our weighted-average cost of capital, we may choose to delay completions and/or forego drilling altogether. Conversely, if commodity prices move higher, we may choose to accelerate drilling and completion activities.

During the three months ended March 31, 2018, we drilled 28 operated horizontal wells and completed 12 operated horizontal wells. As of March 31, 2018, we are the operator of 67 gross (60 net) horizontal wells in progress, which excludes 23 gross (21 net) horizontal wells for which we have only set surface casings. This activity was funded entirely through cash flows from operations. For 2018 as a whole, we expect to drill 117 gross (100 net) operated horizontal wells and complete approximately 116 gross (103 net) operated horizontal wells with mid-length and long laterals targeting the Codell and Niobrara formations.

For the three months ended March 31, 2018, we participated in the completion of 7 gross (1 net) non-operated horizontal wells. As of March 31, 2018, we are participating in 37 gross (9 net) non-operated horizontal wells in progress. The Company is actively conveying its interests in many of the underlying non-operated wells in progress through signed or anticipated agreements.

### **Trends and Outlook**

Oil traded at \$60.46 per Bbl on December 29, 2017, but has since increased approximately 7% as of March 30, 2018 to \$64.87. Natural gas traded at \$2.95 per Mcf on December 29, 2017, but declined approximately 7% as of March 30, 2018 to \$2.73. Although oil prices have increased in the first quarter of 2018, they continue to be volatile and are out of our control. If oil prices decrease, this could (i) reduce our cash flow which, in turn, could reduce the funds available for exploring and replacing oil and natural gas reserves, (ii) reduce our Revolver borrowing base capacity and increase the difficulty of obtaining equity and debt financing and worsen the terms on which such financing may be obtained, (iii) reduce the number of oil and gas prospects which have reasonable economic returns, (iv) cause us to allow leases to expire based upon the value of potential oil and natural gas reserves in relation to the costs of exploration, (v) result in marginally productive oil and natural gas wells being abandoned as non-commercial, and (vi) cause ceiling test impairments.

Other factors that will most significantly affect our results of operations include (i) activities on properties that we operate, (ii) the marketability of our production, (iii) the availability and capacity of gathering systems, pipelines, and other midstream infrastructure for our production, (iv) our ability to satisfy our financial and volume commitment obligations, (v) completion of acquisitions of additional properties and reserves, and (vi) competition from other oil and gas companies.

We utilize what we believe to be industry best practices in our effort to achieve optimal hydrocarbon recoveries. Currently, our practice is to drill 16 to 24 horizontal wells per 640-acre section depending upon specific geologic attributes and existing vertical wellbore development.

We have been able to reduce drilling and completion costs due to a combination of optimizing well designs, fewer average days to drill, and lower completion costs. This focus on cost reduction has supported well-level economics giving consideration

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to the current prices of oil and natural gas. We continue to strive to reduce drilling and completion costs going forward, but as commodity prices improve and industry activity increases, we may experience higher service costs.

Midstream companies that operate the natural gas processing facilities and gathering pipelines in the Wattenberg Field continue to make significant capital investments to increase the capacity of their systems. From time to time, our production has been adversely impacted by the lack of processing capacity resulting in high natural gas gathering line pressures.

To address the growing volumes of natural gas production in the D-J Basin, DCP Midstream has initiated plans for multiple projects including new processing plants, low pressure gathering systems, additional compression, and plant bypass infrastructure. Most notably, in collaboration with DCP Midstream, we and several other producers have agreed to support the expansion of natural gas gathering and processing capacity through agreements that impose baseline and incremental volume commitments, which we are currently exceeding. The initial plan includes a new 200 MMcf per day processing plant as well as the expansion of a related gathering system, both expected to be operational in the third quarter of 2018. Additionally, through the same framework, all of the parties agreed to a development plan to add another 200 MMcf/d plant in mid-2019.

We have extended the use of oil and water gathering lines to certain production locations. These gathering systems are owned and operated by independent third parties, and we commit specific leases or areas to these systems. We believe these gathering lines have several benefits, including a) reduced need to use trucks, thereby reducing truck traffic and noise in and around our production locations, b) potentially lower gathering costs as pipeline gathering tends to be more efficient, c) reduced on-site storage capacity, resulting in lower production location facility costs, and d) generally improved community relations. As these gathering lines are currently being expanded, we have experienced and expect to continue to experience some delays in placing our pads on production.

Oil transportation and takeaway capacity has increased with the expansion of certain interstate pipelines servicing the Wattenberg Field. We strive to reduce the negative differential that we have historically realized on our oil production depending on transportation commitments, local refinery demand, and our production volumes. Further details regarding posted prices and average realized prices are discussed in "-Market Conditions."

As of March 31, 2018, we have identified over 1,700 drilling locations across our acreage position in the core of the Wattenberg Field. For 2018, we expect to drill 117 gross operated horizontal wells with mostly mid-length and long laterals targeting the Codell and Niobrara zones. We anticipate this drilling and completion program will cost between \$480 million and \$540 million and will lead to a significant increase in production and associated proved developed producing reserves. We expect our production to be somewhat flat over the first half of the year and then to accelerate over the second half of the year as additional natural gas processing capacity is completed in the basin. We currently estimate that full-year 2018 production will average between 48,000 BOED and 52,000 BOED, with oil making up 47% - 50% of production.

Other than the foregoing, we do not know of any trends, events, or uncertainties that have had, during the periods covered by this report, or are reasonably expected to have, a material impact on our sales, revenues, expenses, liquidity, or capital resources.

### **Results of Operations**

Material changes to certain items in our condensed consolidated statements of operations included in our condensed consolidated financial statements for the periods presented are discussed below.

#### ***For the three months ended March 31, 2018 compared to the three months ended March 31, 2017***

For the three months ended March 31, 2018, we reported net income of \$65.8 million compared to net income of \$19.9 million during the three months ended March 31, 2017. Net income per basic and diluted share was \$0.27 for the three months ended March 31, 2018 compared to net income per basic and diluted share of \$0.10 for the three months ended March 31, 2017. Net income per basic share for the three months ended March 31, 2018 increased by \$0.17.

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*Oil, Natural Gas, and NGL Production and Revenues* - For the three months ended March 31, 2018, we recorded total oil, natural gas, and NGL revenues of \$147.2 million compared to \$43.8 million for the three months ended March 31, 2017, an increase of \$103.4 million or 236%. The following table summarizes key production and revenue statistics:

	Three Months Ended March 31,		Percentage Change
	2018	2017	
<b>Production:</b>			
Oil (MBbls) <sup>1</sup>	2,041	680	200 %
Natural Gas (MMcf) <sup>2</sup>	7,719	3,446	124 %
NGLs (MBbls) <sup>1</sup>	758	343	121 %
MBOE <sup>3</sup>	4,086	1,597	156 %
BOED <sup>4</sup>	45,397	17,743	156 %
<b>Revenues (in thousands):</b>			
Oil	\$ 116,204	\$ 29,149	299 %
Natural Gas	16,517	9,179	80 %
NGLs	14,512	5,462	166 %
	<u>\$ 147,233</u>	<u>\$ 43,790</u>	236 %
<b>Average sales price:</b>			
Oil <sup>5</sup>	\$ 56.01	\$ 42.50	32 %
Natural Gas	2.14	2.66	(20)%
NGLs	19.15	15.94	20 %
BOE <sup>5</sup>	\$ 35.58	\$ 27.27	30 %

<sup>1</sup> "MBbl" refers to one thousand stock tank barrels, or 42,000 U.S. gallons liquid volume in reference to crude oil or other liquid hydrocarbons.

<sup>2</sup> "MMcf" refers to one million cubic feet of natural gas.

<sup>3</sup> "MBOE" refers to one thousand barrels of oil equivalent, which combines MBbls of oil and MMcf of natural gas by converting each six MMcf of natural gas to one MBbl of oil.

<sup>4</sup> "BOED" refers to the average number of barrels of oil equivalent produced in a day for the period.

<sup>5</sup> Adjusted to include the effect of transportation and gathering expenses.

Net oil, natural gas, and NGL production for the three months ended March 31, 2018 averaged 45,397 BOED, an increase of 156% over average production of 17,743 BOED in the three months ended March 31, 2017. From March 31, 2017 to March 31, 2018, our well count increased by 119 net horizontal wells, growing our reserves and daily production totals. The 156% increase in production and the 30% increase in average sales prices resulted in a significant increase in revenues.

*LOE* - Direct operating costs of producing oil and natural gas are reported as follows (in thousands):

	Three Months Ended March 31,	
	2018	2017
Production costs	\$ 7,714	\$ 3,473
Workover	182	249
Total LOE	<u>\$ 7,896</u>	<u>\$ 3,722</u>
<b>Per BOE:</b>		
Production costs	\$ 1.89	\$ 2.17
Workover	0.04	0.16
Total LOE	<u>\$ 1.93</u>	<u>\$ 2.33</u>

Lease operating and workover costs tend to increase or decrease primarily in relation to the number and type of wells, our overall production volumes, and to a lesser extent, on fluctuations in oil field service costs. During the three months ended March 31, 2018, we experienced increased production expense compared to three months ended March 31, 2017 due to a 80%

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increase in net operated wells and a 156% increase in production volumes. Unit operating costs benefited from larger volumes of production on the horizontal wells turned to sales over the last twelve months.

*Transportation and gathering* - During 2017, the Company entered into new gathering agreements which resulted in new transportation and gathering charges. Transportation and gathering was \$1.9 million, or \$0.45 per BOE, for the three months ended March 31, 2018, compared to \$0.3 million, or \$0.16 per BOE, for the three months ended March 31, 2017. While reported as an expense, the Company analyzes these charges on a net basis within revenue.

*Production taxes* - Production taxes are comprised primarily of two elements: severance tax and ad valorem tax. Production taxes were \$13.4 million, or \$3.29 per BOE, for the three months ended March 31, 2018, compared to \$1.5 million, or \$0.92 per BOE, during the three months ended March 31, 2017. Taxes tend to increase or decrease primarily based on the value of production sold. As a percentage of revenues, production taxes were 9.1% and 3.3% for the three months ended March 31, 2018 and 2017, respectively. During the three months ended March 31, 2017, the Company reduced its estimate for production taxes based on recent historical experience and additional information received during the period. Based on this analysis, the Company's prior year accruals were reduced, resulting in an approximate \$2.0 million reduction to our production taxes during the three months ended March 31, 2017.

*DD&A* - The following table summarizes the components of DD&A:

(in thousands)	Three Months Ended March 31,	
	2018	2017
Depletion of oil and gas properties	\$ 36,102	\$ 12,703
Depreciation and accretion	979	526
Total DD&A	\$ 37,081	\$ 13,229
DD&A expense per BOE	\$ 9.08	\$ 8.28

For the three months ended March 31, 2018, DD&A was \$9.08 per BOE compared to \$8.28 per BOE for the three months ended March 31, 2017. The increase in the DD&A rate was the result of recent drilling and completion activities which increased the amortization base. Capitalized costs of proved oil and gas properties are depleted quarterly using the units-of-production method based on estimated reserves, wherein the ratio of production volumes for the quarter to beginning of quarter estimated total reserves determined the depletion rate.

*General and Administrative ("G&A")* - The following table summarizes G&A expenses incurred and capitalized during the periods presented:

(in thousands)	Three Months Ended March 31,	
	2018	2017
G&A costs incurred	\$ 12,741	\$ 10,880
Capitalized costs	(3,141)	(2,680)
Total G&A	\$ 9,600	\$ 8,200
Non-Cash G&A	\$ 2,796	\$ 2,675
Cash G&A	6,804	5,525
Total G&A	\$ 9,600	\$ 8,200
Non-Cash G&A per BOE	\$ 0.68	\$ 1.68
Cash G&A per BOE	1.67	3.46
G&A Expense per BOE	\$ 2.35	\$ 5.14

G&A includes all overhead costs associated with employee compensation and benefits, insurance, facilities, professional fees, and regulatory costs, among others. Total G&A costs of \$9.6 million for the first quarter of 2018 were 17% higher than G&A for the same period of 2017. This increase is primarily due to a 31% increase in employee headcount from 105 at March 31, 2017 to 138 at March 31, 2018.

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Our G&A expense for the three months ended March 31, 2018 includes stock-based compensation of \$2.8 million compared to \$2.7 million for the three months ended March 31, 2017.

Pursuant to the requirements under the full cost accounting method for oil and gas properties, we identify all general and administrative costs that relate directly to the acquisition of undeveloped mineral leases and the exploration and development of properties. Those costs are reclassified from G&A expenses and capitalized into the full cost pool. The increase in capitalized costs from the three months ended March 31, 2017 to the three months ended March 31, 2018 reflects our increased headcount of individuals performing activities to maintain and acquire leases and develop our properties.

*Commodity derivative gains (losses)* - As more fully described in Item 1. Financial Statements – Note 8, *Commodity Derivative Instruments*, we use commodity contracts to help mitigate the risks inherent in the price volatility of oil and natural gas. For the three months ended March 31, 2018, we realized a cash settlement loss of \$2.1 million, net of previously incurred premiums attributable to the settled commodity contracts. For the prior comparable period, we realized a cash settlement loss of \$119.0 thousand, net of previously incurred premiums attributable to the settled commodity contracts.

In addition, for the three months ended March 31, 2018, we recorded an unrealized loss of \$3.7 million to recognize the mark-to-market change in fair value of our commodity contracts. In comparison, in the three months ended March 31, 2017, we reported an unrealized gain of \$3.5 million. Unrealized gains and losses are non-cash items.

*Income taxes* - As more fully described in Item 1. Financial Statements – Note 13, *Income Taxes*, we reported income tax expense of \$5.8 million for the three months ended March 31, 2018 as compared to no income tax expense for the comparable prior year period. The effective tax rates for the three months ended March 31, 2018 and 2017 differed from the statutory rates due primarily to the release of valuation allowances previously recorded against deferred tax assets.

### **Liquidity and Capital Resources**

Historically, our primary sources of capital have been net cash provided by cash flow from operations, proceeds from the sale of properties, the sale of equity and debt securities, and borrowings under bank credit facilities. Our primary use of capital has been for the exploration, development, and acquisition of oil and gas properties. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us.

We believe that our capital resources, including cash flows from operating activities, cash on hand, and amounts available under our revolving credit facility will be sufficient to fund our planned capital expenditures and operating expenses for the next twelve months. To the extent actual operating results differ from our anticipated results, available borrowings under our credit facility are reduced, or we experience other unfavorable events, our liquidity could be adversely impacted. Our liquidity would also be affected if we increase our capital expenditures or complete one or more additional acquisitions. Terms of future financings may be unfavorable, and we cannot assure investors that funding will be available on acceptable terms.

As operator of the majority of our wells and undeveloped acreage, we control the timing and selection of new wells to be drilled. This allows us to modify our capital spending as our financial resources allow and market conditions support. Additionally, our relatively low utilization of debt enhances our financial flexibility as it provides a potential source of future liquidity while currently not overly burdening us with restrictive financial covenants and mandatory repayment schedules.

### **Sources and Uses**

Our sources and uses of capital are heavily influenced by the prices that we receive for our production. Oil and gas markets will likely continue to be volatile in the future. To deal with the volatility in commodity prices, we maintain a flexible capital investment program and seek to maintain a high operating interest in our leaseholds with limited long-term capital commitments. This enables us to accelerate or decelerate our activities quickly in response to changing industry environments.

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At March 31, 2018, we had cash, cash equivalents, and restricted cash of \$71.7 million, \$550.0 million outstanding on our Senior 2025 Notes, and no balance outstanding under our revolving credit facility. Our sources and (uses) of funds for the three months ended March 31, 2018 and 2017 are summarized below (in thousands):

	Three Months Ended March 31,	
	2018	2017
Net cash provided by operations	\$ 127,681	\$ 29,358
Capital expenditures	(105,633)	(85,034)
Net cash provided by other investing activities	728	70,689
Net cash provided by (used in) equity financing activities	431	(431)
Net cash used in debt financing activities	(236)	—
Net increase in cash, cash equivalents, and restricted cash	\$ 22,971	\$ 14,582

Net cash provided by operating activities was \$127.7 million and \$29.4 million for the three months ended March 31, 2018 and 2017, respectively. The increase in cash from operating activities reflects the increase in realized commodity prices and production.

Net cash provided by other investing activities was \$0.7 million and \$70.7 million for the three months ended March 31, 2018 and 2017, respectively, which were primarily comprised of proceeds from the sale of oil and gas properties.

#### **Credit Facility**

The Revolver has a maturity date of April 2, 2023. The Revolver has a maximum loan commitment of \$1.5 billion; however, the maximum amount available to be borrowed at any one time is subject to a borrowing base limitation, which stipulates that we may borrow up to the least of the aggregate maximum credit amount, the aggregate elected commitment, or the borrowing base. The borrowing base can increase or decrease based upon the value of the collateral, which secures any amounts borrowed under the Revolver. The value of the collateral will generally be derived with reference to the estimated discounted future net cash flows from our proved oil and natural gas reserves. The collateral includes substantially all of our producing wells and developed oil and gas leases.

As a result of entering into the Restated Credit Agreement with certain banks and other lenders on April 2, 2018, the borrowing base was increased from \$400 million to \$550 million; however, our elected commitment amount was \$450 million. As of March 31, 2018, there was no principal balance outstanding and \$0.5 million in letters of credit outstanding, leaving \$399.5 million available to us for future borrowings. After giving effect to the Restated Credit Agreement, the amount available to us for future borrowings increased to \$449.5 million. The next semi-annual redetermination is scheduled for November 2018. Interest on the Revolver accrues at a variable rate. The interest rate pricing grid provides for an escalation in applicable margin based on increased utilization of the Revolver.

The Revolver requires the Company to maintain compliance with certain financial and liquidity ratio covenants. In particular, the Company must not (a) permit its ratio of total funded debt to EBITDAX, as defined in the agreement, to be greater than or equal to 4.0 to 1.0 as of the last day of any fiscal quarter or (b) permit its ratio of current assets to current liabilities, each as defined in the agreement, to be less than 1.0 to 1.0 as of the last day of any fiscal quarter.

#### **2025 Senior Notes**

In November 2017, the Company issued \$550 million aggregate principal amount of 6.25% Senior Notes in a private placement to qualified institutional buyers. The maturity for the payment of principal is December 1, 2025. Interest on the 2025 Senior Notes accrues at 6.25% and began accruing on November 29, 2017. Interest is payable on June 1 and December 1 of each year, beginning on June 1, 2018. The 2025 Senior Notes were issued pursuant to an indenture dated as of November 29, 2017 and are guaranteed on a senior unsecured basis by the Company's existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under the Revolver. At any time prior to December 1, 2020, the Company may redeem all or a part of the 2025 Senior Notes at a redemption price equal to 100% of the principal amount plus an Applicable Premium (as defined in the Indenture) plus accrued and unpaid interest. On and after December 1, 2020, the Company may redeem all or a part of the 2025 Senior Notes at the redemption price equal to a specified percentage of the principal amount of the redeemed notes (104.688% for 2020, 103.125% for 2021, 101.563% for 2022, and 100% for 2023 and thereafter, during the twelve-month period beginning on December 1 of each applicable year), plus accrued and unpaid interest. Additionally, prior to December 1, 2020, the Company can, on one or more occasions, redeem up to 35% of the principal amount of the 2025 Senior



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Notes with all or a portion of the net cash proceeds of one or more Equity Offerings (as defined in the Indenture) at a redemption price equal to 106.25% of the principal amount of the redeemed notes, plus accrued and unpaid interest, subject to certain conditions.

The Indenture contains covenants that restrict the Company's ability and the ability of certain of its subsidiaries to, among other restrictions and limitations: (i) incur additional indebtedness; (ii) incur liens; (iii) pay dividends; (iv) consolidate, merge, or transfer all or substantially all of its or their assets; (v) engage in transactions with affiliates; or (vi) engage in certain restricted business activities. These covenants are subject to a number of exceptions and qualifications.

### Capital Expenditures

Capital expenditures for drilling and completion activities totaled \$111.0 million and \$93.2 million for the three months ended March 31, 2018 and 2017, respectively. The following table summarizes our capital expenditures for oil and gas properties (in thousands):

	Three Months Ended March 31,	
	2018	2017
Capital expenditures for drilling and completion activities	\$ 111,009	\$ 93,176
Acquisitions of oil and gas properties and leasehold*	9,284	27,493
Capitalized interest, capitalized G&A, and other	13,346	5,323
Accrual basis capital expenditures**	\$ 133,639	\$ 125,992

\*Acquisitions of oil and gas properties and leasehold reflects the full purchase price of our various acquisitions which includes non-cash additions for liabilities assumed in the transaction such as asset retirement obligations.

\*\*Capital expenditures reported in the condensed consolidated statement of cash flows are calculated on a cash basis, which differs from the accrual basis used to calculate the capital expenditures.

During the three months ended March 31, 2018, we drilled 28 operated horizontal wells and turned 12 operated horizontal wells to sales. As of March 31, 2018, we are the operator of 67 gross (60 net) horizontal wells in progress, which excludes 23 gross (21 net) wells for which we have only surface casings. All of the wells in progress at March 31, 2018 are scheduled to commence production before December 31, 2019. This activity was funded entirely through cash flows from operations.

For the three months ended March 31, 2018, we participated in 44 gross (10 net) non-operated horizontal wells.

### Capital Requirements

Our level of exploration, development, and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows, development results, and downstream infrastructure and commitments, among other factors. Our primary need for capital will be to fund our anticipated drilling and completion activities and any other acquisitions that we may complete during 2018.

We anticipate that our 2018 drilling and completion capital expenditures for operated wells will cost between \$480 million and \$540 million for the year. However, should commodity prices and/or economic conditions change, we can reduce or accelerate our drilling and completion activities, which could have a material impact on our anticipated capital requirements.

For the near term, we believe that we have sufficient liquidity to fund our needs through cash on hand, cash flow from operations, and additional borrowings available under our revolving credit facility. However, should this not meet all of our long-term needs, we may need to raise additional funds to drill new wells through the sale of our securities, from third parties willing to pay our share of drilling and completing wells, or from other sources. We may not be successful in raising the capital needed to drill or acquire oil or natural gas wells. We may seek to raise funds in capital markets transactions from time to time if we believe market conditions to be favorable.

### Oil and Natural Gas Commodity Contracts

We use derivative contracts to help protect against the variability in cash flows created by short-term price fluctuations associated with the sale of future oil and natural gas production. At March 31, 2018, we had open positions covering 2.8 million barrels of oil and 4,125 MMcf of natural gas. We do not use derivative instruments for speculative purposes.

Our commodity derivative instruments may include but are not limited to "collars," "swaps," and "put" positions. Our derivative strategy, including the volumes and commodities covered and the relevant strike prices, is based in part on our view of

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expected future market conditions and our analysis of well-level economic return potential. In addition, our use of derivative contracts is subject to stipulations set forth in our credit facility.

During the three months ended March 31, 2018, we reported an unrealized commodity activity loss of \$3.7 million. Unrealized losses are non-cash items. We also reported a realized loss of \$2.1 million, representing the cash settlement of commodity contracts settled during the period, net of previously incurred premiums attributable to the settled commodity contracts.

At March 31, 2018, we estimated that the fair value of our various commodity derivative contracts was a net liability of \$11.6 million. See Item 1. Financial Statements – Note 9, *Fair Value Measurements*, for a description of the methods we use to estimate the fair values of commodity derivative instruments.

### Non-GAAP Financial Measures

In addition to financial measures presented on the basis of accounting principles generally accepted in the United States of America ("US GAAP"), we present certain financial measures which are not prescribed by US GAAP ("non-GAAP"). The following is a summary of the measure we currently report.

#### Adjusted EBITDA

We use "adjusted EBITDA," a non-GAAP financial measure, for internal managerial purposes because it allows us to evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed in the table below from net income in arriving at adjusted EBITDA. We exclude those items because they can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures, and the method by which the assets were acquired. Adjusted EBITDA is not a measure of financial performance under US GAAP and should be considered in addition to, not as a substitute for, net income. We believe that adjusted EBITDA is widely used in our industry as a measure of operating performance and may also be used by investors to measure our ability to meet debt covenant requirements. However, our definition of adjusted EBITDA may not be fully comparable to measures with similar titles reported by other companies. We define adjusted EBITDA as net income adjusted to exclude the impact of the items set forth in the table below (amounts in thousands):

	Three Months Ended March 31,	
	2018	2017
Adjusted EBITDA:		
Net income	\$ 65,796	\$ 19,880
Depreciation, depletion, and accretion	37,081	13,229
Stock-based compensation expense	2,796	2,675
Mark-to-market of commodity derivative contracts:		
Total (gain) loss on commodity derivatives contracts	5,781	(3,379)
Cash settlements on commodity derivative contracts	(1,555)	81
Interest income, net of interest expense	(9)	(11)
Income tax expense	5,811	—
Adjusted EBITDA	<u>\$ 115,701</u>	<u>\$ 32,475</u>

### Critical Accounting Policies

We prepare our condensed consolidated financial statements and the accompanying notes in conformity with US GAAP, which requires management to make estimates and assumptions about future events that affect the reported amounts in the condensed consolidated financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition, results of operations, or liquidity and the degree of difficulty, subjectivity, and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management discusses the development, selection, and disclosure of each of the critical accounting policies.

There have been no significant changes to our critical accounting policies and estimates or in the underlying accounting assumptions and estimates used from those disclosed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of the Annual Report on Form 10-K filed with the SEC on February 21, 2018 and in the financial

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statements and accompanying notes contained in that report. Item 1. Financial Statements – Note 1, *Organization and Summary of Significant Accounting Policies*, to the accompanying condensed consolidated financial statements included elsewhere in this report provides information regarding recently issued accounting pronouncements.

### Cautionary Statement Concerning Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are subject to risks and uncertainties and are based on the beliefs and assumptions of management and information currently available to management. The use of words such as "believes," "expects," "anticipates," "intends," "plans," "estimates," "should," "likely," or similar expressions indicate forward-looking statements. Forward-looking statements included in this report include statements relating to future production, future capital expenditures and projects, the adequacy and nature of future sources of financing, possible future impairment charges, midstream capacity issues, future differentials, future production relative to volume commitments, and the closing and effect of proposed transactions.

The identification in this report of factors that may affect our future performance and the accuracy of forward-looking statements is meant to be illustrative and by no means exhaustive. All forward-looking statements should be evaluated with the understanding of their inherent uncertainty.

See "*Risk Factors*" in this report and in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017 filed with the SEC on February 21, 2018 for a discussion of risk factors that affect our business, financial condition, and results of operations. These risks include, among others, those associated with the following:

- declines in oil and natural gas prices;
- operating hazards that adversely affect our ability to conduct business;
- uncertainties in the estimates of proved reserves;
- the effect of seasonal weather conditions and wildlife and plant species restrictions on our operations;
- our ability to fund, develop, produce, and acquire additional oil and natural gas reserves that are economically recoverable;
- our ability to obtain adequate financing;
- the effect of local and regional factors on oil and natural gas prices;
- incurrence of ceiling test write-downs;
- our inability to control operations on properties that we do not operate;
- the availability and capacity of gathering systems, pipelines, and other midstream infrastructure for our production;
- the strength and financial resources of our competitors;
- our ability to complete, and the effect of, pending and planned transactions;
- our ability to successfully identify, execute, and effectively integrate acquisitions;
- the effect of federal, state, and local laws and regulations;
- the effects of, including costs to comply with, environmental legislation or regulatory initiatives, including those related to hydraulic fracturing;
- our ability to market our production;
- the effects of local moratoria or bans on our business;
- the effect of environmental liabilities;
- the effect of the adoption and implementation of statutory and regulatory requirements for derivative transactions;
- changes in U.S. tax laws;
- our ability to satisfy our contractual obligations and commitments;
- the amount of our indebtedness and our ability to maintain compliance with debt covenants;
- the effectiveness of our disclosure controls and our internal controls over financial reporting;
- the geographic concentration of our principal properties;
- our ability to protect critical data and technology systems;
- the availability of water for use in our operations; and
- the risks and uncertainties described and referenced in "Risk Factors."

**ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS**

**Commodity Price Risk** - Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. The volatility of oil prices affects our results to a greater degree than the volatility of natural gas prices, as approximately 79% of our revenue during the three months ended March 31, 2018 was from the sale of oil. A \$5 per barrel change in our realized oil price would have resulted in a \$10.2 million change in revenues during the three months ended March 31, 2018, a \$0.25 per Mcf change in our realized natural gas price would have resulted in a \$1.9 million change in our natural gas revenues for the three months ended March 31, 2018, and a \$5 per barrel change in our realized NGL price would have resulted in a \$3.8 million change in our NGL revenues for the three months ended March 31, 2018.

During the three months ended March 31, 2018, the price of oil, natural gas, and NGLs increased relative to the first quarter of 2017. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil, natural gas, and NGL prices include the levels of demand and supply for oil (in global or local markets), the establishment of and compliance with production quotas by oil exporting countries, weather conditions which influence the demand for natural gas, the price and availability of alternative fuels, the strength of the US dollar compared to other currencies, and overall economic conditions. It is impossible to predict future oil, natural gas, and NGLs prices with any degree of certainty. Sustained weakness in oil, natural gas, and NGL prices may adversely affect our financial condition and results of operations and may also reduce the amount of oil, natural gas, and NGL reserves that we can produce economically. Any reduction in our oil, natural gas, and NGL reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil, natural gas, and NGL prices can have a favorable impact on our financial condition, results of operations, and capital resources.

We attempt to mitigate fluctuations in short-term cash flow resulting from changes in commodity prices by entering into derivative positions on a portion of our expected oil and natural gas production. Under the Revolver, we can use derivative contracts to cover up to 85% of expected proved developed producing production as projected in our semi-annual reserve report, generally over a period of two years. We do not enter into derivative contracts for speculative or trading purposes. As of March 31, 2018, we had open oil and natural gas derivatives in a net liability position with a fair value of \$11.6 million. A hypothetical upward shift of 10% in the NYMEX forward curve of oil and natural gas prices would decrease the fair value of our position by \$10.8 million. A hypothetical downward shift of 10% in the NYMEX forward curve of oil and natural gas prices would increase the fair value of our position by \$3.2 million.

**Interest Rate Risk** - At March 31, 2018, we had no debt outstanding under our revolving credit facility. Interest on our credit facility accrues at a variable rate, based upon either the Prime Rate or LIBOR plus an applicable margin. During the three months ended March 31, 2018, we incurred no interest expense on our revolving credit facility. When we have balances outstanding under the revolving credit facility, we are exposed to interest rate risk on the credit facility if the variable reference rates increase. If interest rates increase, our monthly interest payments would increase and our available cash flow would decrease. We estimate that if market interest rates increased or decreased by 1%, the change to our interest payments in the three months ended March 31, 2018 would be insignificant.

Under current market conditions, we do not anticipate significant changes in prevailing interest rates for the next year, and we have not undertaken any activities to mitigate potential interest rate risk due to restrictions imposed by the Revolver.

**Counterparty Risk** - As described in "- Commodity Price Risk" above, we enter into commodity derivative agreements to mitigate short-term price volatility. These derivative financial instruments present certain counterparty risks. We are exposed to potential loss if a counterparty fails to perform according to the terms of the agreement. The failure of any of the counterparties to fulfill their obligations to us could adversely affect our results of operations and cash flows. We do not require collateral or other security to be furnished by counterparties. We seek to manage the counterparty risk associated with these contracts by limiting transactions to well capitalized, well established, and well-known counterparties that have been approved by our senior officers. There can be no assurance, however, that our practice effectively mitigates counterparty risk.

We believe that our exposure to counterparty risk decreased slightly during the first quarter of 2018 as the amounts due from us to counterparties has increased.

**ITEM 4. CONTROLS AND PROCEDURES**

**Evaluation of Disclosure Controls and Procedures**

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this report on Form 10-Q (the "Evaluation Date"). Based on such evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of the Evaluation Date, our disclosure controls and procedures were effective.

**Changes in Internal Control over Financial Reporting**

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

**PART II****Item 1. Legal Proceedings**

Except as disclosed in Note 15 to the accompanying condensed consolidated financial statements, during the quarter, there were no material developments regarding legal matters, which were previously described under Item 3, *Legal Proceedings*, of the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 21, 2018. This information should be considered carefully together with other information in this report and other reports and materials we file with the SEC.

**Item 1A. Risk Factors**

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity, and the trading price of our common stock are described under Item 1A, Risk Factors, of the Annual Report on Form 10-K filed with the SEC on February 21, 2018. This information should be considered carefully together with other information in this report and other reports and materials that we file with the SEC.

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

Purchases of equity securities by the Company

<u>Period</u>	<u>Total Number of Shares Purchased</u>	<u>Average Price Paid per Share</u>
January 1, 2018 - January 31, 2018 <sup>(1)</sup>	25,339	\$ 8.86
February 1, 2018 - February 28, 2018 <sup>(1)</sup>	25,772	\$ 9.19
March 1, 2018 - March 31, 2018 <sup>(1)</sup>	25,906	\$ 9.42
Total	77,017	

(1) Pursuant to statutory minimum withholding requirements, certain of our employees exercised their right to "withhold to cover" as a tax payment method for the vesting and exercise of certain shares. These elections were outside of any publicly announced repurchase plan.

**Item 3. Defaults Upon Senior Securities**

None.

**Item 4. Mine Safety Disclosures**

Not applicable

**Item 5. Other Information**

None

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**Item 6. Exhibits**

<b>Exhibit Number</b>	<b>Exhibit</b>
31.1	<a href="#">Certification of the Principal Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as adopted, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</a> *
31.2	<a href="#">Certification of the Principal Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as adopted, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</a> *
32.1	<a href="#">Certifications of the Principal Executive Officer and Principal Financial Officer pursuant to 18 USC 1350, as adopted, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002</a> **
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

\* Filed herewith

\*\* Furnished herewith



**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(a) 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 on the 2nd day of May, 2018.

**SRC Energy Inc.**

/s/ Lynn A. Peterson

Lynn A. Peterson, President and Chief Executive Officer  
(Principal Executive Officer)

/s/ James P. Henderson

James P. Henderson, Executive Vice President, Chief Financial Officer, and  
Treasurer  
(Principal Financial Officer)

/s/ Jared C. Grenzenbach

Jared C. Grenzenbach, Vice President and Chief Accounting Officer  
(Principal Accounting Officer)

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER  
PURSUANT TO 15 U.S.C. SECTION 7241, AS  
ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Lynn A. Peterson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of SRC Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 2, 2018

/s/ Lynn A. Peterson  
Lynn A. Peterson  
Principal Executive Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER  
PURSUANT TO 15 U.S.C. SECTION 7241, AS  
ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, James P. Henderson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of SRC Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by the report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 2, 2018

/s/ James P. Henderson  
James P. Henderson,  
Principal Financial Officer

CERTIFICATIONS OF  
PRINCIPAL EXECUTIVE AND FINANCIAL OFFICERS  
PURSUANT TO 18 U.S.C. SECTION 1350, AS  
ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of SRC Energy Inc., (the "Company") on Form 10-Q for the quarter ended March 31, 2018 as filed with the Securities Exchange Commission on the date hereof (the "Report") Lynn A. Peterson, Principal Executive Officer of the Company, and James P. Henderson, Principal Financial Officer of the Company, certify pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of their knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

Date: May 2, 2018

By: /s/ Lynn A. Peterson  
Lynn A. Peterson, Principal Executive Officer

Date: May 2, 2018

By: /s/ James P. Henderson  
James P. Henderson, Principal Financial Officer

