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 June 30, 2018

OR

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

For the transition period from ________________________ to ________________________

Commission file number: 001-35245

SRC ENERGY

SRC ENERGY INC.
(Exact name of registrant as specified in its charter)

COLORADO	**20-2835920**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1675 Broadway, Suite 2600, Denver, CO	**80202**
(Address of principal executive offices)	(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.

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: 242,518,525 outstanding shares of common stock as of July 31, 2018.

SRC ENERGY INC.

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

ASSETS	June 30, 2018	December 31, 2017
Current assets:		
Cash and cash equivalents	$ 53,145	$ 48,772
Accounts receivable:		
Oil, natural gas, and NGL sales	81,299	86,013
Trade	20,159	18,134
Other current assets	8,609	7,116
Total current assets	163,212	160,035
Property and equipment:		
Oil and gas properties, full cost method:		
Proved properties, net of accumulated depletion	1,131,313	970,584
Wells in progress	159,173	106,269
Unproved properties and land, not subject to depletion	775,717	793,669
Oil and gas properties, net	2,066,203	1,870,522
Other property and equipment, net	6,126	6,054
Total property and equipment, net	2,072,329	1,876,576
Commodity derivative assets	204	—
Goodwill	40,711	40,711
Other assets	6,090	2,242
Total assets	$ 2,282,546	$ 2,079,564
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 95,685	$ 74,672
Revenue payable	69,488	64,111
Production taxes payable	60,624	52,413
Asset retirement obligations	3,963	3,246
Commodity derivative liabilities	20,189	7,865
Total current liabilities	249,949	202,307
Revolving credit facility	25,000	—
Notes payable, net of issuance costs	538,762	538,186
Asset retirement obligations	23,154	28,376
Deferred taxes	9,158	—
Other liabilities	2,398	2,261
Total liabilities	848,421	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, 400,000,000 and 300,000,000 shares authorized: 242,496,080 and 241,365,522 shares issued and outstanding as of June 30, 2018 and December 31, 2017, respectively	242	241
Additional paid-in capital	1,484,543	1,474,273
Retained deficit	(50,660)	(166,080)
Total shareholders' equity	1,434,125	1,308,434
Total liabilities and shareholders' equity	$ 2,282,546	$ 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil, natural gas, and NGL revenues	$ 147,087	$ 75,036	$ 294,320	$ 118,826
Expenses:				
Lease operating expenses	11,612	4,970	19,508	8,692
Transportation and gathering	1,880	48	3,735	298
Production taxes	15,058	9,464	28,501	10,930
Depreciation, depletion, and accretion	41,877	26,427	78,958	39,656
Unused commitment charge	—	—	—	669
General and administrative	9,406	7,605	19,006	15,805
Total expenses	79,833	48,514	149,708	76,050
Operating income	67,254	26,522	144,612	42,776
Other income (expense):				
Commodity derivatives gain (loss)	(14,294)	1,328	(20,075)	4,707
Interest expense, net of amounts capitalized	—	—	—	—
Interest income	5	20	14	31
Other income	6	66	27	302
Total other income (expense)	(14,283)	1,414	(20,034)	5,040
Income before income taxes	52,971	27,936	124,578	47,816
Income tax expense	3,347	—	9,158	—
Net income	$ 49,624	$ 27,936	$ 115,420	$ 47,816
Net income per common share:				
Basic	$ 0.20	$ 0.14	$ 0.48	$ 0.24
Diluted	$ 0.20	$ 0.14	$ 0.47	$ 0.24
Weighted-average shares outstanding:				
Basic	242,255,724	200,831,063	242,005,211	200,769,817
Diluted	244,464,776	201,224,172	243,954,673	201,266,609

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)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Cash flows from operating activities:		
Net income	$ 115,420	$ 47,816
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and accretion	78,958	39,656
Settlement of asset retirement obligation	(4,089)	(1,392)
Provision for deferred taxes	9,158	—
Stock-based compensation expense	5,942	5,360
Mark-to-market of commodity derivative contracts:		
Total loss (gain) on commodity derivatives contracts	20,075	(4,707)
Cash settlements on commodity derivative contracts	(6,121)	234
Changes in operating assets and liabilities:	16,419	(12,509)
Net cash provided by operating activities	235,762	74,458
Cash flows from investing activities:		
Acquisition of oil and gas properties and leaseholds	(16,402)	(29,998)
Capital expenditures for drilling and completion activities	(213,906)	(178,606)
Other capital expenditures	(23,823)	(8,858)
Acquisition of land and other property and equipment	(1,581)	(3,808)
Proceeds from sales of oil and gas properties and other	766	77,155
Net cash used in investing activities	(254,946)	(144,115)
Cash flows from financing activities:		
Proceeds from the employee exercise of stock options	4,192	114
Payment of employee payroll taxes in connection with shares withheld	(1,010)	(565)
Proceeds from the revolving credit facility	25,000	110,000
Principal repayments on the revolving credit facility	—	(20,000)
Fees on debt and equity issuances and revolving credit facility amendments	(2,165)	(255)
Capital lease payments	(135)	—
Net cash provided by financing activities	25,882	89,294
Net increase in cash, cash equivalents, and restricted cash	6,698	19,637
Cash, cash equivalents, and restricted cash at beginning of period	48,772	36,834
Cash, cash equivalents, and restricted cash at end of period	$ 55,470	$ 56,471

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 "SRCI."

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.

Cash Held in Escrow: Cash held in escrow includes deposits for purchases of certain oil and gas properties as required under the related purchase and sale agreements. The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the consolidated balance sheets to the consolidated statements of cash flows:

	As of June 30,	
	2018	2017
Cash and cash equivalents	$ 53,145	$ 36,677
Restricted cash included in Cash held in escrow and other deposits	—	19,794
Restricted cash included in Other assets	2,325	—
	$ 55,470	$ 56,471

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:

	Three Months Ended June 30,		Six Months Ended June 30,	
Major Customers	2018	2017	2018	2017
Company A	32%	24%	17%	25%
Company B	21%	*	17%	*
Company C	19%	16%	33%	17%
Company D	17%	28%	17%	26%
Company E	*	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.

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 June 30, 2018	As of December 31, 2017
Company A	27%	26%
Company B	20%	16%
Company C	10%	23%
Company D	10%	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. 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 a have a material impact on our reported financial position, results of operations, or cash flows.

2. Property and Equipment

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

	As of June 30, 2018	As of December 31, 2017
Oil and gas properties, full cost method:		
Costs of proved properties:		
Producing and non-producing	$ 1,869,421	$ 1,629,789
Less, accumulated depletion and full cost ceiling impairments	(738,108)	(659,205)
Subtotal, proved properties, net	1,131,313	970,584
Costs of wells in progress	159,173	106,269
Costs of unproved properties and land, not subject to depletion:		
Lease acquisition and other costs	767,526	786,469
Land	8,191	7,200
Subtotal, unproved properties and land	775,717	793,669
Costs of other property and equipment:		
Other property and equipment	9,155	8,134
Less, accumulated depreciation	(3,029)	(2,080)
Subtotal, other property and equipment, net	6,126	6,054
Total property and equipment, net	$ 2,072,329	$ 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 June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Capitalized overhead	$ 3,280	$ 2,531	$ 6,393	$ 5,211

3. Acquisitions

August 2018 Acquisition and Swap

In June 2018, the Company entered into an agreement to purchase leasehold acreage and the associated non-operated production for $31.0 million, subject to customary closing adjustments. Upon signing, the Company deposited $2.3 million into an escrow account. The acreage increases our working interest in our existing operations and planned wells. The acquisition is expected to close in August 2018.

Following the 2018 second quarter end, we reached an agreement with another party to trade approximately 2,500 net acres. This transaction will further enhance the contiguous nature of the Company's acreage position.

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 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 transaction completed at 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.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Depletion of oil and gas properties	$ 40,927	$ 25,742	$ 77,029	$ 38,445
Depreciation and accretion	950	685	1,929	1,211
Total DD&A Expense	$ 41,877	$ 26,427	$ 78,958	$ 39,656

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 and six months ended June 30, 2018, production of 4,336 MBOE and 8,422 MBOE, respectively, represented 1.9% and 3.6% of estimated total proved reserves, respectively. For the three and six months ended June 30, 2017, production of 2,969 MBOE and 4,566 MBOE, respectively, represented 1.9% and 2.9% of estimated total proved reserves, respectively. DD&A expense was $9.66 per BOE and $8.90 per BOE for the three months ended June 30, 2018 and 2017, respectively and was $9.38 per BOE and $8.69 per BOE for the six months ended June 30, 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):

	Six Months Ended June 30, 2018
Asset retirement obligations, December 31, 2017	$ 31,622
Obligations incurred with development activities	473
Obligations assumed with acquisitions	5
Accretion expense	981
Obligations discharged with asset retirements and divestitures	(5,964)
Asset retirement obligation, June 30, 2018	$ 27,117
Less, current portion	(3,963)
Long-term portion	$ 23,154

6. 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. The Restated Credit Agreement provides a revolving credit facility (sometimes referred to as the "Revolver") and a $25 million swingline facility 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, and general corporate purposes and to support letters of credit. At June 30, 2018, the terms of the Revolver provided for up to $1.5 billion in borrowings, an aggregate elected commitment of $450 million, and a borrowing base limitation of $550 million. As of June 30, 2018 and December 31, 2017, the outstanding principal balance was $25.0 million and nil, respectively. At June 30, 2018, the Company had no letters of credit issued.

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 six months ended June 30, 2018 and 2017 was 4.0% and 2.8%, respectively.

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 of June 30, 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 may be guaranteed in the future on a senior unsecured basis by certain of the Company's subsidiaries. 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 GCII 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. The indenture governing the 2025 Senior Notes provides that, in certain circumstances, the notes will be guaranteed by one or more subsidiaries of the Company, in which case such guarantee would be made on a full and unconditional and joint and several senior unsecured basis.

As of June 30, 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 seven counterparties. Five of the counterparties are lenders in the Restated Credit Agreement. 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 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 June 30, 2018 are summarized below:

Settlement Period	Derivative Instrument	Volumes (Bbls per day)	Weighted-Average Floor Price	Weighted-Average Ceiling Price
Crude Oil - NYMEX WTI				
Jul 1, 2018 - Dec 31, 2018	Collar	10,000	$ 43.63	$ 61.29
Jan 1, 2019 - Dec 31, 2019	Collar	3,000	$ 55.00	$ 73.50

Settlement Period	Derivative Instrument	Volumes (MMBtu per day)	Weighted-Average Floor Price	Weighted-Average Ceiling Price
Natural Gas - CIG Rocky Mountain				
Jul 1, 2018 - Dec 31, 2018	Collar	15,000	$ 2.25	$ 2.82

Settlement Period	Derivative Instrument	Volumes (Bbls per day)	Fixed Price
Propane - Mont Belvieu			
Jul 1, 2018 - Dec 31, 2018	Swap	1,000	$ 33.60

Offsetting of Derivative Assets and Liabilities

As of June 30, 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):

		As of June 30, 2018		
Underlying	Balance Sheet Location	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	$ 1,355	$ (1,355)	$ —
Commodity derivative contracts	Noncurrent assets	$ 1,978	$ (1,774)	$ 204
Commodity derivative contracts	Current liabilities	$ 21,544	$ (1,355)	$ 20,189
Commodity derivative contracts	Noncurrent liabilities	$ 1,774	$ (1,774)	$ —

		As of December 31, 2017		
Underlying	Balance Sheet Location	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	$ —	$ —	$ —

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Realized loss on commodity derivatives	$ (5,883)	$ (23)	$ (7,955)	$ (142)
Unrealized gain (loss) on commodity derivatives	(8,411)	1,351	(12,120)	4,849
Total gain (loss)	$ (14,294)	$ 1,328	$ (20,075)	$ 4,707

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Monthly settlement	$ (5,883)	$ 327	$ (7,955)	$ 551
Previously incurred premiums attributable to settled commodity contracts	—	(350)	—	(693)
Total realized loss	$ (5,883)	$ (23)	$ (7,955)	$ (142)

Credit Related Contingent Features

As of June 30, 2018, five of the seven 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 sixth and seventh counterparties, which are not lenders under the credit facility, is unsecured and does not require the posting of collateral.

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 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 June 30, 2018			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Commodity derivative asset	$ —	$ 204	$ —	$ 204
Commodity derivative liability	$ —	$ 20,189	$ —	$ 20,189

	Fair Value Measurements at December 31, 2017			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
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 June 30, 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 valued 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 $555.5 million at June 30, 2018. The Company determined the fair value of its notes payable at June 30, 2018 by using observable market based information for these debt instruments. The Company has classified the notes payable as Level 1.

10. Interest Expense

The components of interest expense are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revolving bank credit facility	$ 85	$ 227	$ 85	$ 270
Notes payable	8,594	1,800	17,188	3,600
Amortization of issuance costs and other	1,113	677	2,000	1,177
Less: interest capitalized	(9,792)	(2,704)	(19,273)	(5,047)
Interest expense, net of amounts capitalized	$ —	$ —	$ —	$ —

11. Equity and Stock-Based Compensation

Equity

At the 2018 annual meeting of shareholders of the Company held on May 18, 2018, the shareholders approved the Third Amended and Restated Articles of Incorporation of the Company to increase the number of authorized shares of common stock of the Company from 300,000,000 to 400,000,000.

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 June 30, 2018, there were 10,500,000 common shares authorized for grant under the 2015 Equity Incentive Plan, of which 4,303,404 shares were available for future grant. The shares available for future grant exclude 1,555,263 shares which have been reserved for future vesting of performance-vested stock units in the event that these awards meet the criteria to vest at their maximum multiplier.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Stock options	$ 1,195	$ 1,302	$ 2,398	$ 2,548
Performance-vested stock units	1,173	798	2,029	1,323
Restricted stock units and stock bonus shares	1,400	1,047	2,736	2,393
Total stock-based compensation	$ 3,768	$ 3,147	$ 7,163	$ 6,264
Less: stock-based compensation capitalized	(622)	(462)	(1,221)	(904)
Total stock-based compensation expensed	$ 3,146	$ 2,685	$ 5,942	$ 5,360

Stock options

No stock options were granted during the three and six months ended June 30, 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	(806,283)	5.34		4,550
Expired	(23,400)	11.27		
Forfeited	(65,467)	9.81		
Outstanding, June 30, 2018	4,741,684	$ 10.05	6.9 years	$ 6,019
Outstanding, Exercisable at June 30, 2018	2,921,030	$ 10.33	6.7 years	$ 3,036

The following table summarizes information about issued and outstanding stock options as of June 30, 2018:

	Outstanding Options			Exercisable Options		
Range of Exercise Prices	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	35,000	$ 3.31	4.0 years	35,000	$ 3.31	4.0 years
$5.00 - $6.99	741,400	6.30	7.0 years	342,800	6.23	5.7 years
$7.00 - $10.99	1,401,784	9.41	7.0 years	705,830	9.43	6.7 years
$11.00 - $13.46	2,563,500	11.58	6.9 years	1,837,400	11.57	6.9 years
Total	4,741,684	$ 10.05	6.9 years	2,921,030	$ 10.33	6.7 years

The estimated unrecognized compensation cost from stock options not vested as of June 30, 2018, which will be recognized ratably over the remaining vesting phase, is as follows:

Unrecognized compensation cost (in thousands)	$ 6,956
Remaining vesting phase	1.9 years

Restricted stock units and stock bonus awards

The Company grants restricted stock units and stock bonus awards to directors, eligible employees, and officers under 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.

The following table summarizes activity for restricted stock units and stock bonus awards for the six months ended June 30, 2018:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Not vested, December 31, 2017	1,087,386	$ 8.89
Granted	661,676	9.14
Vested	(371,450)	8.51
Forfeited	(43,813)	9.71
Not vested, June 30, 2018	1,333,799	$ 9.09

The estimated unrecognized compensation cost from restricted stock units and stock bonus awards not vested as of June 30, 2018, which will be recognized ratably over the remaining vesting phase, is as follows:

Unrecognized compensation cost (in thousands)	$ 10,001
Remaining vesting phase	2.3 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:

	Six Months Ended June 30,	
	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%

The fair value of the TSR PSUs granted during the six months ended June 30, 2018 and 2017 was $4.2 million and $5.1 million, respectively. As of June 30, 2018, unrecognized compensation cost for TSR PSUs was $7.2 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[1]	Weighted-Average Grant-Date Fair Value
Not vested, December 31, 2017	951,884	$ 9.44
Granted	321,507	13.11
Vested	—	—
Forfeited	—	—
Not vested, June 30, 2018	1,273,391	$ 10.36

[1] 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 - These PSUs vest after 2020 and are to be based on long-term corporate goals that have not been finalized by the Compensation Committee. Thus, 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 June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Weighted-average shares outstanding — basic	242,255,724	200,831,063	242,005,211	200,769,817
Potentially dilutive common shares from:				
Stock options	421,316	360,423	387,634	411,819
TSR PSUs [1]	1,372,019	—	1,223,542	—
Restricted stock units and stock bonus shares	415,717	32,686	338,286	84,973
Weighted-average shares outstanding — diluted	244,464,776	201,224,172	243,954,673	201,266,609

[1] 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Potentially dilutive common shares from:				
Stock options [1]	3,353,700	4,786,500	3,564,617	4,786,500
TSR PSUs [1,2]	—	951,884	—	951,884
Corporate Goals PSUs [2,3]	281,872	—	281,872	—
Restricted stock units and stock bonus shares [1]	2,772	872,193	10,005	522,014
Total	3,638,344	6,610,577	3,856,494	6,260,398

[1] Potential common shares excluded from weighted-average shares outstanding-diluted calculation as the securities had an anti-dilutive effect on earnings per share.
[2] 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.
[3] 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 and six months ended June 30, 2018 were 6% and 7%, respectively. For the three and six months ended June 30, 2017, the effective tax rates were nil. The effective tax rates for the three and six months ended June 30, 2018 and 2017 differed from the statutory rates due primarily to the release of valuation allowances previously recorded against deferred tax assets.

As of June 30, 2018, we had no liability for unrecognized tax benefits. The Company believes that there are no new items or 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 June 30, 2018. The Company’s policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of June 30, 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 June 30, 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
Revenues (in thousands):	2018	2017	2018	2017
Oil	$ 114,857	$ 51,939	$ 231,061	$ 81,088
Natural Gas and NGLs	32,230	23,097	63,259	37,738
	$ 147,087	$ 75,036	$ 294,320	$ 118,826

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 that 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. As of June 30, 2018, we had contract assets recorded within other current assets of $1.7 million representing cash advances to customers which are expected to be realized within a year.

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 and six months ended June 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

15. Other Commitments and Contingencies

Volume Commitments

The Company entered into firm sales agreements for its oil production with four counterparties. Deliveries under three of the sales agreements have commenced. 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	2,375
2019	5,167
2020	4,003
2021	1,672
2022	—
Thereafter	—
Total	13,217

During the second 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 ("Mewbourn 3") as well as the expansion of a related gathering system. Mewbourn 3 is mechanically complete, is currently being commissioned, and is expected to be in service in August 2018. 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 includes a new 200 MMcf per day processing plant ("O'Connor 2") as well as the expansion of a related gathering system. Construction of the plant is underway and is expected to be placed into service in the second quarter of 2019. 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 the Company's business, financial position, results of operations, or cash flows.

Office leases

The Company's principal office space located in Denver is under lease through July 2022. Current rent under the lease is approximately $66,000 per month. The Company also has a field office lease in Greeley which requires monthly payments of $7,500 through October 2021.

Rent expense for offices leases was $0.2 million and $0.2 million for the three months ended June 30, 2018 and 2017, respectively. For the six months ended June 30, 2018 and 2017, rent expense for office leases was $0.5 million and $0.6 million, 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."

A schedule of the minimum lease payments under non-cancellable capital and operating leases as of June 30, 2018 follows (in thousands):

Year ending December 31:	Vehicles Leases	Office Leases
Remainder of 2018	$ 101	$ 607
2019	134	896
2020	134	916
2021	161	913
2022	98	500
Thereafter	—	—
Total minimum lease payments	$ 628	$ 3,832
Less: Amount representing estimated executory cost	(50)	
Net minimum lease payments	578	
Less: Amount representing interest	(80)	
Present value of net minimum lease payments *	$ 498	

* Reflected in the balance sheet as current and non-current obligations of $123 thousand and $375 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):

	Six Months Ended June 30,	
Supplemental cash flow information:	2018	2017
Interest paid	$ 17,448	$ 3,864
Income taxes paid	—	—
Non-cash investing and financing activities:		
Accrued well costs as of period end	$ 75,705	$ 87,699
Asset retirement obligations incurred with development activities	473	1,527
Asset retirement obligations assumed with acquisitions	5	1,098
Obligations discharged with asset retirements and divestitures	$ (5,964)	$ (4,500)
Net changes in operating assets and liabilities:		
Accounts receivable	$ 2,797	$ (33,628)
Accounts payable and accrued expenses	(42)	(2,071)
Revenue payable	5,377	18,400
Production taxes payable	8,199	5,714
Other	88	(924)
Changes in operating assets and liabilities	$ 16,419	$ (12,509)

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 June 30, 2018 and its results of operations for the three and six months ended June 30, 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 and referenced 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, 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 81% of our proved developed reserves and anticipate operating a majority 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

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil (NYMEX-WTI)				
Average NYMEX Price	$ 68.03	$ 48.24	$ 65.46	$ 50.08
Realized Price *	61.22	41.11	58.48	41.60
Differential *	$ (6.81)	$ (7.13)	$ (6.98)	$ (8.48)
Natural Gas (NYMEX-Henry Hub)				
Average NYMEX Price	$ 2.80	$ 3.08	$ 2.90	$ 3.04
Realized Price	1.64	2.29	1.87	2.42
Differential	$ (1.16)	$ (0.79)	$ (1.03)	$ (0.62)
NGL Realized Price	$ 17.65	$ 13.18	$ 18.30	$ 14.12

* 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. With regard to the sale of oil, substantially all of the Company's first quarter 2017 oil production was sold to the counterparties of its firm sales commitments. Beginning in the second quarter of 2017, the Company's oil production exceeded its firm sales commitments, and the surplus oil production was sold at a reduced differential as compared to our committed volumes.

Our revenues, results of operations, profitability, future growth, and carrying value of our oil and gas properties depend primarily on the prices that we receive for our oil, natural gas, and NGL production. There has been significant volatility in the price of oil and natural gas since mid-2014. During the six months ended June 30, 2018, the NYMEX-WTI oil price ranged from a high of $77.41 per Bbl on June 27, 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 $74.13 per Bbl on Friday, June 29, 2018, an increase of 23% from December 29, 2017. NYMEX-Henry Hub natural gas traded at $2.95 per Mcf on December 29, 2017, but declined approximately 1% as of June 29, 2018 to $2.92. While we use NYMEX-Henry Hub to calculate our natural gas differentials, our natural gas sales tend to trend more closely with Colorado Interstate Gas – Rocky Mountains as published in Inside FERC’s Gas Market Report, published by Platts ("CIG"). Average CIG prices for the second quarter of 2018 decreased to $1.83 from $2.42 in the first quarter of 2018, and the basis difference for CIG to NYMEX-Henry Hub increased from $0.58 to $0.97.

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 June 30, 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.

Core Operations

The following table provides details about our ownership interests with respect to vertical and horizontal producing wells as of June 30, 2018:

Vertical Wells					
Operated Wells		Non-Operated Wells		Totals	
Gross	Net	Gross	Net	Gross	Net
250	240	203	61	453	301

Horizontal Wells					
Operated Wells		Non-Operated Wells		Totals	
Gross	Net	Gross	Net	Gross	Net
257	245	295	56	552	301

In addition to the producing wells summarized in the preceding table, as of June 30, 2018, we were the operator of 73 gross (65 net) horizontal wells in progress, which excludes 22 gross (19 net) wells for which we have only set surface casings. As of June 30, 2018, we are participating in 26 gross (7 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 six months ended June 30, 2018, we plugged 97 wells and returned the associated acreage to the property owners.

Production

For the three months ended June 30, 2018, our average daily production increased to 47,646 BOED as compared to 32,624 BOED for the three months ended June 30, 2017. During the first six months of 2018, our average net daily production was 46,528 BOED. By comparison, during the six months ended June 30, 2017, our average production rate was 25,224 BOED. As of June 30, 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.

- *Control and reduce emissions from our production facilities*. We place high importance on achieving compliance with all applicable air quality rules and regulations and reducing emissions continues to be a top environmental priority. To minimize these emissions, we employ best management practices such as using available direct pipeline take-away access and pneumatic actuated instrument devices. We also control emissions and minimize flaring of gas by recovering natural gas and actively pursuing sufficient take-away capacity for associated produced gas and the use of vapor recovery equipment. We continue to evolve the design of our production facilities to produce oil and natural gas with fewer air emissions, including those emissions for which there are public health standards (e.g. ozone and particulate matter).

Significant Developments

Acquisition and Swap

During the second quarter of 2018, the Company entered into an agreement to purchase leasehold acreage and associated production for $31 million. This transaction increases the Company's working interest in existing operations and planned wells. Following the 2018 second quarter end, we reached an agreement with another party to trade approximately 2,500 net acres. These transactions further enhance the contiguous nature of the Company's acreage position.

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. Relative to the prior credit agreement, the Restated Credit Agreement also 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 six months ended June 30, 2018, we drilled 59 operated horizontal wells and turned 16 operated horizontal wells to sales. As of June 30, 2018, the Company had 20 gross (18 net) wells that were drilled and completed, but not producing.

These wells were not turned to sales during the second quarter due to a lack of processing capacity that is expected to be alleviated during the third quarter. As of June 30, 2018, we are the operator of 73 gross (65 net) horizontal wells in progress, which excludes 22 gross (19 net) horizontal wells for which we have only set surface casings. This activity was funded primarily 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 six months ended June 30, 2018, we participated in the completion of 22 gross (4 net) non-operated horizontal wells. As of June 30, 2018, we are participating in 26 gross (7 net) non-operated horizontal wells in progress.

Trends and Outlook

NYMEX-WTI oil traded at $60.46 per Bbl on December 29, 2017, but has since increased approximately 23% as of June 29, 2018 to $74.13. NYMEX-Henry Hub natural gas traded at $2.95 per Mcf on December 29, 2017, but declined approximately 1% as of June 29, 2018 to $2.92. Although NYMEX-WTI oil prices have increased in the first half 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 could, in turn, 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.

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.

Over the last three years, 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 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 have improved and industry activity has increased, we have experienced 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 and may continue to be adversely impacted by the lack of processing capacity resulting in high natural gas gathering line pressures. Second quarter 2018 results were impacted by this lack of spare gas processing capacity, which resulted in persistently high line pressures and the inability to maintain consistent production flows. Further exacerbating the midstream constraints were above average temperatures in Colorado in June and continuing into July as well as unplanned shutdowns of natural gas processing facilities. As a result, many of the Company's legacy wells could not be produced consistently, and the Company was unable to turn recently completed wells to sales as desired.

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 ("Mewbourn 3") as well as the expansion of a related gathering system, both expected to be operational in August 2018. Additionally, through the same framework, all of the parties agreed to a development plan to add another 200 MMcf/d plant ("O'Connor 2") that is expected to be in service in the second quarter of 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 June 30, 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 (59 of which were drilled through June 30, 2018) 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 ($231.2 million of which was incurred through June 30, 2018) and which should lead to a significant increase in production and associated proved developed producing reserves. We expect our production 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 and 52,000 BOED. With the lack of spare capacity for gas processing, our oil mix dropped to approximately 46% during the first six months of the year, and we expect our full year oil mix to be at the lower end of our guidance of 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 June 30, 2018 compared to the three months ended June 30, 2017

For the three months ended June 30, 2018, we reported net income of $49.6 million compared to net income of $27.9 million during the three months ended June 30, 2017. Net income per basic and diluted share was $0.20 for the three months ended June 30, 2018 compared to net income per basic and diluted share of $0.14 for the three months ended June 30, 2017. Net income per basic share for the three months ended June 30, 2018 increased by $0.06.

Oil, Natural Gas, and NGL Production and Revenues - For the three months ended June 30, 2018, we recorded total oil, natural gas, and NGL revenues of $147.1 million compared to $75.0 million for the three months ended June 30, 2017, an increase of $72.1 million or 96%. The following table summarizes key production and revenue statistics:

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Percentage Change
Production:			
Oil (MBbls) [1]	1,846	1,262	46 %
Natural Gas (MMcf) [2]	8,987	6,264	43 %
NGLs (MBbls) [1]	992	662	50 %
MBOE [3]	4,336	2,969	46 %
BOED [4]	47,646	32,624	46 %
Revenues (in thousands):			
Oil	$ 114,857	$ 51,939	121 %
Natural Gas	14,714	14,364	2 %
NGLs	17,516	8,733	101 %
	$ 147,087	$ 75,036	96 %
Average sales price:			
Oil [5]	$ 61.22	$ 41.11	49 %
Natural Gas	1.64	2.29	(28)%
NGLs	17.65	13.18	34 %
BOE [5]	$ 33.50	$ 25.26	33 %

[1] "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.
[2] "MMcf" refers to one million cubic feet of natural gas.
[3] "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.
[4] "BOED" refers to the average number of barrels of oil equivalent produced in a day for the period.
[5] Adjusted to include the effect of transportation and gathering expenses.

Net oil, natural gas, and NGL production for the three months ended June 30, 2018 averaged 47,646 BOED, an increase of 46% over average production of 32,624 BOED in the three months ended June 30, 2017. From June 30, 2017 to June 30, 2018, our well count increased by 117 net horizontal wells, growing our reserves and daily production totals. The 46% increase in production and the 33% 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 June 30, 2018	Three Months Ended June 30, 2017
Production costs	$ 11,433	$ 4,815
Workover	179	155
Total LOE	$ 11,612	$ 4,970
Per BOE:		
Production costs	$ 2.64	$ 1.62
Workover	0.04	0.05
Total LOE	$ 2.68	$ 1.67

Lease operating and workover costs tend to increase or decrease primarily in relation to the number and type of wells and, to a lesser extent, on fluctuations in oil field service costs and changes in the production mix of oil and natural gas. During the three months ended June 30, 2018, we experienced increased production expense compared to the three months ended June 30, 2017 due to a 63% increase in net operated wells. In addition, elevated line pressures temporarily drove operating costs on a unit basis higher in the second quarter of 2018 as the Company incurred incremental costs without the typical benefit of flush production from its new wells.

Transportation and gathering - Transportation and gathering was $1.9 million, or $0.43 per BOE, for the three months ended June 30, 2018, compared to $49 thousand, or $0.02 per BOE, for the three months ended June 30, 2017. In the first half of 2017, a majority of the Company's production was delivered to the purchaser at the wellhead whereas, in 2018, the Company has increased the proportion of its production that is sold and delivered at the downstream interconnect. This has the effect of increasing both the net price received for the production and transportation and gathering costs. While costs attributable to volumes sold at the interconnect of the pipeline are reported as an expense, the Company analyzes these charges on a net basis within revenue for comparability with wellhead sales.

Production taxes - Production taxes are comprised primarily of two elements: severance tax and ad valorem tax. Production taxes were $15.1 million, or $3.47 per BOE, for the three months ended June 30, 2018, compared to $9.5 million, or $3.19 per BOE, during the three months ended June 30, 2017. Taxes tend to increase or decrease primarily based on the value of production sold. As a percentage of revenues, production taxes were 10.2% and 12.6% for the three months ended June 30, 2018 and 2017, respectively.

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

	Three Months Ended June 30,	
(in thousands)	2018	2017
Depletion of oil and gas properties	$ 40,927	$ 25,742
Depreciation and accretion	950	685
Total DD&A	$ 41,877	$ 26,427
DD&A expense per BOE	$ 9.66	$ 8.90

For the three months ended June 30, 2018, DD&A was $9.66 per BOE compared to $8.90 per BOE for the three months ended June 30, 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:

	Three Months Ended June 30,	
(in thousands)	2018	2017
G&A costs incurred	$ 12,721	$ 10,136
Capitalized costs	(3,315)	(2,531)
Total G&A	$ 9,406	$ 7,605
Non-Cash G&A	$ 3,146	$ 2,685
Cash G&A	6,260	4,920
Total G&A	$ 9,406	$ 7,605
Non-Cash G&A per BOE	$ 0.73	$ 0.90
Cash G&A per BOE	1.44	1.66
G&A Expense per BOE	$ 2.17	$ 2.56

G&A includes overhead costs associated with employee compensation and benefits, insurance, facilities, professional fees, and regulatory costs, among others. Total G&A costs of $9.4 million for the second quarter of 2018 were 24% higher than G&A for the same period of 2017. This increase is primarily due to a 26% increase in employee headcount from 112 at June 30, 2017 to 141 at June 30, 2018.

Our G&A expense for the three months ended June 30, 2018 includes stock-based compensation of $3.1 million compared to $2.7 million for the three months ended June 30, 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 June 30, 2017 to the three months ended June 30, 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 June 30, 2018, we realized a cash settlement loss of $5.9 million. For the prior comparable period, we realized a cash settlement loss of $23.0 thousand, net of previously incurred premiums attributable to the settled commodity contracts.

In addition, for the three months ended June 30, 2018, we recorded an unrealized loss of $8.4 million to recognize the mark-to-market change in fair value of our commodity contracts. In comparison, in the three months ended June 30, 2017, we reported an unrealized gain of $1.4 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 $3.3 million for the three months ended June 30, 2018 as compared to no income tax expense for the comparable prior year period. The effective tax rates for the three and six months ended June 30, 2018 and 2017 differed from the statutory rates due primarily to the release of valuation allowances previously recorded against deferred tax assets.

For the six months ended June 30, 2018 compared to the six months ended June 30, 2017

For the six months ended June 30, 2018, we reported net income of $115.4 million compared to net income of $47.8 million during the six months ended June 30, 2017. Net income per basic and diluted share was $0.48 and $0.47, respectively, for the six months ended June 30, 2018 compared to net income per basic and diluted share of $0.24 for the six months ended June 30, 2017. Net income per basic share for the six months ended June 30, 2018 increased by $0.24.

Oil, Natural Gas, and NGL Production and Revenues - For the six months ended June 30, 2018, we recorded total oil, natural gas, and NGL revenues of $294.3 million compared to $118.8 million for the six months ended June 30, 2017, an increase of $175.5 million or 148%. The following table summarizes key production and revenue statistics:

	Six Months Ended June 30,				Percentage
	2018		2017		Change
Production:					
Oil (MBbls)		3,887		1,942	100 %
Natural Gas (MMcf)		16,706		9,710	72 %
NGLs (MBbls)		1,750		1,005	74 %
MBOE		8,422		4,566	84 %
BOED		46,528		25,224	84 %
Revenues (in thousands):					
Oil	$	231,061	$	81,088	185 %
Natural Gas		31,231		23,543	33 %
NGLs		32,028		14,195	126 %
	$	294,320	$	118,826	148 %
Average sales price:					
Oil	$	58.48	$	41.60	41 %
Natural Gas		1.87		2.42	(23)%
NGLs		18.30		14.12	30 %
BOE	$	34.50	$	25.96	33 %

Net oil, natural gas, and NGL production for the six months ended June 30, 2018 averaged 46,528 BOED, an increase of 84% over average production of 25,224 BOED in the six months ended June 30, 2017. From June 30, 2017 to June 30, 2018, our well count increased by 117 net horizontal wells, growing our reserves and daily production totals. The 84% increase in production and 33% 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):

	Six Months Ended June 30,			
	2018		2017	
Production costs	$	19,147	$	8,288
Workover		361		404
Total LOE	$	19,508	$	8,692
Per BOE:				
Production costs	$	2.27	$	1.82
Workover		0.04		0.09
Total LOE	$	2.31	$	1.91

Lease operating and workover costs tend to increase or decrease primarily in relation to the number and type of wells and, to a lesser extent, on fluctuations in oil field service costs and changes in the production mix of oil and natural gas. During the six months ended June 30, 2018, we experienced increased production expense compared to the six months ended June 30, 2017 primarily due to a 63% increase in net operated wells. In addition, elevated line pressures temporarily drove operating costs on a unit basis higher in the second quarter of 2018 as the Company incurred incremental costs without the typical benefit of flush production from its new wells.

Transportation and gathering - Transportation and gathering was $3.7 million, or $0.44 per BOE, for the six months ended June 30, 2018, compared to $0.3 million, or $0.07 per BOE, for the six months ended June 30, 2017. In the first half of 2017, a majority of the Company's production was delivered to the purchaser at the wellhead whereas, in 2018, the Company has increased the proportion of its production that is sold and delivered at the downstream interconnect. This has the effect of increasing both the net price received for the production and transportation and gathering costs. While costs attributable to volumes sold at the interconnect of the pipeline are reported as an expense, the Company analyzes these charges on a net basis within revenue for comparability with wellhead sales.

Production taxes - Production taxes are comprised primarily of two elements: severance tax and ad valorem tax. Production taxes were $28.5 million, or $3.38 per BOE, for the six months ended June 30, 2018, compared to $10.9 million, or $2.39 per BOE, for the six months ended June 30, 2017. Taxes tend to increase or decrease primarily based on the value of production sold. As a percentage of revenues, production taxes were 9.7% and 9.2% for the six months ended June 30, 2018 and 2017, respectively.

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

	Six Months Ended June 30,	
(in thousands)	2018	2017
Depletion of oil and gas properties	$ 77,029	$ 38,445
Depreciation and accretion	1,929	1,211
Total DD&A	$ 78,958	$ 39,656
DD&A expense per BOE	$ 9.38	$ 8.69

For the six months ended June 30, 2018, DD&A was $9.38 per BOE compared to $8.69 per BOE for the six months ended June 30, 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.

G&A - The following table summarizes G&A expenses incurred and capitalized during the periods presented:

	Six Months Ended June 30,	
(in thousands)	2018	2017
G&A costs incurred	$ 25,462	$ 21,016
Capitalized costs	(6,456)	(5,211)
Total G&A	$ 19,006	$ 15,805
Non-Cash G&A	$ 5,942	$ 5,360
Cash G&A	13,064	10,445
Total G&A	$ 19,006	$ 15,805
Non-Cash G&A per BOE	$ 0.71	$ 1.17
Cash G&A per BOE	1.55	2.29
G&A Expense per BOE	$ 2.26	$ 3.46

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 $19.0 million for the second quarter of 2018 were 20% higher than G&A for the same period of 2016. This increase is primarily due to a 26% increase in employee headcount from 112 at June 30, 2017 to 141 at June 30, 2018.

Our G&A expense for the six months ended June 30, 2018 includes stock-based compensation of $5.9 million compared to $5.4 million for the six months ended June 30, 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 six months ended June 30, 2017 to the six months ended June 30, 2018 reflects our increased headcount of individuals performing activities to maintain and acquire leases and develop our properties.

Commodity derivatives - 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 six months ended June 30, 2018, we realized a cash settlement loss of $8.0 million. For the prior comparable period, we realized a cash settlement loss of $0.1 million, net of previously incurred premiums attributable to the settled commodity contracts.

In addition, for the six months ended June 30, 2018, we recorded an unrealized loss of $12.1 million to recognize the mark-to-market change in fair value of our commodity contracts. In comparison, in the six months ended June 30, 2017, we reported an unrealized gain of $4.8 million. Unrealized gains and losses are non-cash items.

Income taxes - We reported income tax expense of $9.2 million for the six months ended June 30, 2018 as compared to no income tax expense for the comparable prior year period. During the six months ended June 30, 2018 and 2017, the effective tax rate differed from the statutory rate 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 current 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. During the six months ended June 30, 2018, our drilling and completions expenditures were primarily covered by cash flows from operating activities. 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.

At June 30, 2018, we had cash, cash equivalents, and restricted cash of $53.1 million, $550.0 million outstanding on our Senior 2025 Notes, and a $25.0 million balance outstanding under our revolving credit facility. Our sources and (uses) of funds for the six months ended June 30, 2018 and 2017 are summarized below (in thousands):

	Six Months Ended June 30,	
	2018	2017
Net cash provided by operations	$ 235,762	$ 74,458
Capital expenditures	(255,712)	(221,270)
Net cash provided by other investing activities	766	77,155
Net cash provided by (used in) equity financing activities	3,025	(451)
Net cash provided by debt financing activities	22,857	89,745
Net increase in cash, cash equivalents, and restricted cash	$ 6,698	$ 19,637

Net cash provided by operating activities was $235.8 million and $74.5 million for the six months ended June 30, 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 $0.8 million and $77.2 million for the six months ended June 30, 2018 and 2017, respectively, which were primarily comprised of proceeds from the sale of oil and gas properties and other.

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 June 30, 2018, there was a $25.0 million principal balance outstanding and no letters of credit outstanding, leaving $425.0 million available to us for future borrowings. 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 (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 may be guaranteed in the future on a senior unsecured basis by certain of the Company’s subsidiaries. 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 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 $231.2 million and $223.5 million for the six months ended June 30, 2018 and 2017, respectively. The following table summarizes our capital expenditures for oil and gas properties (in thousands):

	Six Months Ended June 30,	
	2018	2017
Capital expenditures for drilling and completion activities	$ 231,196	$ 223,496
Acquisitions of oil and gas properties and leasehold*	16,402	32,842
Capitalized interest, capitalized G&A, and other	26,754	11,796
Accrual basis capital expenditures**	$ 274,352	$ 268,134

*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 six months ended June 30, 2018, we drilled 59 operated horizontal wells and turned 16 operated horizontal wells to sales. As of June 30, 2018, the Company had 20 gross (18 net) wells that were drilled and completed, but not producing. These wells were not turned to sales during the second quarter due to a lack of processing capacity that is expected to be alleviated during the third quarter. As of June 30, 2018, we are the operator of 73 gross (65 net) horizontal wells in progress, which excludes 22 gross (19 net) wells for which we have only set surface casings. All of the wells in progress at June 30, 2018 are scheduled to commence production before December 31, 2019. This activity was funded entirely through cash flows from operations.

For the six months ended June 30, 2018, we participated in 48 gross (11 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 full-year 2018 drilling and completion capital expenditures for operated wells will be between $480 million and $540 million. 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 June 30, 2018, we had open positions covering 2.9 million barrels of oil and 2,760 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 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 six months ended June 30, 2018, we reported an unrealized commodity activity loss of $12.1 million. Unrealized losses are non-cash items. We also reported a realized loss of $8.0 million, representing the cash settlement of commodity contracts settled during the period.

At June 30, 2018, we estimated that the fair value of our various commodity derivative contracts was a net liability of $20.0 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Adjusted EBITDA:				
Net income	$ 49,624	$ 27,936	$ 115,420	$ 47,816
Depreciation, depletion, and accretion	41,877	26,427	78,958	39,656
Stock-based compensation expense	3,146	2,685	5,942	5,360
Mark-to-market of commodity derivative contracts:				
Total loss (gain) on commodity derivatives contracts	14,294	(1,328)	20,075	(4,707)
Cash settlements on commodity derivative contracts	(4,566)	153	(6,121)	234
Interest income, net of interest expense	(5)	(20)	(14)	(31)
Income tax expense	3,347	—	9,158	—
Adjusted EBITDA	$ 107,717	$ 55,853	$ 223,418	$ 88,328

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 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 and the construction and effect of additional midstream infrastructure, future differentials, and future production relative to volume commitments.

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 78% of our revenue during the three and six months ended June 30, 2018 was from the sale of oil. A $5 per barrel change in our realized oil price would have resulted in a $9.2 million and $19.4 million change in revenues during the three and six months ended June 30, 2018, respectively, a $0.25 per Mcf change in our realized natural gas price would have resulted in a $2.2 million and $4.2 million change in our natural gas revenues for the three and six months ended June 30, 2018, respectively, and a $5 per barrel change in our realized NGL price would have resulted in a $5.0 million and $8.8 million change in our NGL revenues for the three and six months ended June 30, 2018, respectively.

During the three months ended June 30, 2018, the price of oil, natural gas, and NGLs increased relative to the second 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 June 30, 2018, we had open oil and natural gas derivatives in a net liability position with a fair value of $20.0 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 $13.4 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 $11.3 million.

Interest Rate Risk - At June 30, 2018, we had $25.0 million outstanding under our revolving credit facility. Interest on amounts borrowed under our credit facility accrues at a variable rate, based upon either the Prime Rate or LIBOR plus an applicable margin. During the three and six months ended June 30, 2018, we incurred interest expense of $0.1 million on our revolving credit facility. When we have balances outstanding under the revolving credit facility, we are exposed to interest rate risk if the variable reference rates increase. If interest rates increase, our 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 expense in the three and six months ended June 30, 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 increased slightly during the second quarter of 2018 as the amounts due to us from 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

During the quarter ended June 30, 2018, there were no material developments regarding the legal matters, 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. We are subject to various legal proceedings from time to time in the ordinary course of our business, but there are currently no pending legal proceedings to which we are subject that we believe to be material.

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

Period	Total Number of Shares Purchased	Average Price Paid per Share
April 1, 2018 - April 30, 2018 (1)	823	$ 11.22
May 1, 2018 - May 31, 2018 (1)	23,486	12.11
June 1, 2018 - June 30, 2018 (1)	996	$ 10.70
Total	25,305	

(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

Exhibit Number	Exhibit
3.1	Third Amended and Restated Articles of Incorporation of SRC Energy, Inc. (the "Company") (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K of the Company filed on May 23, 2018)
10.1	Second Amended and Restated Credit Agreement dated as of April 2, 2018, among the Company, SunTrust Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of the Company filed on April 3, 2018)
10.2	SRC Energy Inc. 2015 Equity Incentive Plan, as amended (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of the Company filed on May 23, 2018)
31.1	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 *
31.2	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 *
32.1	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 **
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 1st day of August, 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 and Chief Financial Officer
(Principal Financial Officer)

/s/ Jared C. Grenzenbach

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

Exhibit 31.1

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.

August 1, 2018

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

Exhibit 31.2

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.

August 1, 2018

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

Exhibit 32.1

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 June 30, 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: August 1, 2018

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

Date: August 1, 2018

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