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, 2019

OR

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

For the transition period from ________________________ to ________________________

Commission file number: 001-35245

SRC Energy Inc.
(Exact name of registrant as specified in its charter)

Colorado	**20-2835920**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1675 Broadway, Suite 2600
Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock $.001 par value	SRCI	NYSE American

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 every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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: 243,473,491 outstanding shares of common stock as of July 29, 2019.

SRC ENERGY INC.

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

ASSETS	June 30, 2019	December 31, 2018
Current assets:		
Cash and cash equivalents	$ 27,839	$ 49,609
Accounts receivable:		
Oil, natural gas, and NGL sales	80,510	100,973
Trade	21,961	39,415
Commodity derivative assets	12,061	34,906
Other current assets	7,257	7,537
Total current assets	149,628	232,440
Property and equipment:		
Oil and gas properties, full cost method:		
Proved properties, net of accumulated depletion	1,775,675	1,545,445
Wells in progress	175,400	227,262
Unproved properties and land, not subject to depletion	667,678	740,453
Oil and gas properties, net	2,618,753	2,513,160
Other property and equipment, net	4,881	5,540
Total property and equipment, net	2,623,634	2,518,700
Other assets	11,824	3,574
Total assets	$ 2,785,086	$ 2,754,714
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 76,648	$ 150,010
Revenue payable	95,838	97,030
Production taxes payable	81,905	95,099
Asset retirement obligations	10,608	11,694
Total current liabilities	264,999	353,833
Revolving credit facility	165,000	195,000
Notes payable, net of issuance costs	539,977	539,360
Asset retirement obligations	38,609	40,052
Deferred taxes	74,238	37,967
Other liabilities	4,646	2,210
Total liabilities	1,087,469	1,168,422
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 shares authorized: 243,428,206 and 242,608,284 shares issued and outstanding as of June 30, 2019 and December 31, 2018, respectively	243	243
Additional paid-in capital	1,499,213	1,492,107
Retained earnings	198,161	93,942
Total shareholders' equity	1,697,617	1,586,292
Total liabilities and shareholders' equity	$ 2,785,086	$ 2,754,714

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,	
	2019	2018	2019	2018
Oil, natural gas, and NGL revenues	$ 162,602	$ 147,087	$ 352,057	$ 294,320
Expenses:				
Lease operating expenses	13,230	11,612	30,590	19,508
Transportation and gathering	4,664	1,880	8,718	3,735
Production taxes	13,185	15,058	20,271	28,501
Depreciation, depletion, and accretion	58,027	41,877	118,945	78,958
General and administrative	9,243	9,406	18,712	19,006
Total expenses	98,349	79,833	197,236	149,708
Operating income	64,253	67,254	154,821	144,612
Other income (expense):				
Commodity derivative gain (loss)	8,285	(14,294)	(14,628)	(20,075)
Interest expense, net of amounts capitalized	—	—	—	—
Interest income	92	5	161	14
Other income	75	6	136	27
Total other income (expense)	8,452	(14,283)	(14,331)	(20,034)
Income before income taxes	72,705	52,971	140,490	124,578
Income tax expense	18,237	3,347	36,271	9,158
Net income	$ 54,468	$ 49,624	$ 104,219	$ 115,420
Net income per common share:				
Basic	$ 0.22	$ 0.20	$ 0.43	$ 0.48
Diluted	$ 0.22	$ 0.20	$ 0.43	$ 0.47
Weighted-average shares outstanding:				
Basic	243,404,917	242,255,724	243,348,141	242,005,211
Diluted	244,130,245	244,464,776	243,709,915	243,954,673

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, 2019	Six Months Ended June 30, 2018
Cash flows from operating activities:		
Net income	$ 104,219	$ 115,420
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and accretion	118,945	78,958
Settlement of asset retirement obligations	(4,476)	(4,089)
Provision for deferred taxes	36,271	9,158
Stock-based compensation expense	6,825	5,942
Mark-to-market of commodity derivative contracts:		
Total loss on commodity derivatives contracts	14,628	20,075
Cash settlements on commodity derivative contracts	7,715	(6,121)
Cash premiums paid for commodity derivative contracts	(977)	—
Changes in operating assets and liabilities	18,433	16,419
Net cash provided by operating activities	301,583	235,762
Cash flows from investing activities:		
Acquisition of oil and gas properties and leaseholds, net of post-closing adjustments	116	(16,402)
Capital expenditures for drilling and completion activities	(276,095)	(213,906)
Other capital expenditures	(28,262)	(23,823)
Acquisition of land and other property and equipment	(304)	(1,581)
Proceeds from sales of oil and gas properties and other	12,802	766
Net cash used in investing activities	(291,743)	(254,946)
Cash flows from financing activities:		
Proceeds from the employee exercise of stock options	—	4,192
Payment of employee payroll taxes in connection with shares withheld	(1,126)	(1,010)
Proceeds from the revolving credit facility	—	25,000
Principal repayments on the revolving credit facility	(30,000)	—
Fees on debt and equity issuances and revolving credit facility amendments	(379)	(2,165)
Capital lease payments	(105)	(135)
Net cash provided by (used in) financing activities	(31,610)	25,882
Net increase (decrease) in cash and cash equivalents	(21,770)	6,698
Cash and cash equivalents at beginning of period	49,609	48,772
Cash and cash equivalents at end of period	$ 27,839	$ 55,470

Supplemental Cash Flow Information (See Note 16)

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

SRC ENERGY INC.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(unaudited; in thousands, except share data)

	Number of Common Shares	Par Value Common Stock	Additional Paid-In Capital	Retained Deficit	Total Shareholders' Equity
Balance, December 31, 2017	241,365,522	$ 241	$ 1,474,273	$ (166,080)	$ 1,308,434
Shares issued under stock bonus and equity incentive plans	268,676	1	(1)	—	—
Shares issued for exercise of stock options	268,303	—	1,064	—	1,064
Stock-based compensation	—	—	3,395	—	3,395
Payment of tax withholdings using withheld shares	—	—	(705)	—	(705)
Other activity	—	—	(73)	—	(73)
Net income	—	—	—	65,796	65,796
Balance, March 31, 2018	241,902,501	242	1,477,953	(100,284)	1,377,911
Shares issued under stock bonus and equity incentive plans	69,420	—	—	—	—
Shares issued for exercise of stock options	524,159	—	3,127	—	3,127
Stock-based compensation	—	—	3,768	—	3,768
Payment of tax withholdings using withheld shares	—	—	(305)	—	(305)
Net income	—	—	—	49,624	49,624
Balance, June 30, 2018	242,496,080	$ 242	$ 1,484,543	$ (50,660)	$ 1,434,125

	Number of Common Shares	Par Value Common Stock	Additional Paid-In Capital	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2018	242,608,284	$ 243	$ 1,492,107	$ 93,942	$ 1,586,292
Shares issued under stock bonus and equity incentive plans	709,042	—	—	—	—
Stock-based compensation	—	—	4,413	—	4,413
Payment of tax withholdings using withheld shares	—	—	(876)	—	(876)
Net income	—	—	—	49,751	49,751
Balance, March 31, 2019	243,317,326	243	1,495,644	143,693	1,639,580
Shares issued under stock bonus and equity incentive plans	110,880	—	—	—	—
Stock-based compensation	—	—	3,819	—	3,819
Payment of tax withholdings using withheld shares	—	—	(250)	—	(250)
Net income	—	—	—	54,468	54,468
Balance, June 30, 2019	243,428,206	$ 243	$ 1,499,213	$ 198,161	$ 1,697,617

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, development, and production of oil, natural gas, and natural gas liquids ("NGLs") 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 significant 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, 2018 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, 2018 as filed with the SEC on February 20, 2019. 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, 2018.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Major Customers	2019	2018	2019	2018
Company A	28%	*	26%	*
Company B	20%	17%	21%	17%
Company C	16%	32%	18%	17%
Company D	11%	19%	10%	33%
Company E	*	21%	*	17%

* 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, 2019	As of December 31, 2018
Company A	18%	15%
Company B	15%	12%
Company C	13%	*
Company D	11%	13%
Company E	11%	12%

* 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 February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2016-02, Leases (Topic 842), followed by other related ASUs that provided targeted improvements and additional practical expedient options (collectively "ASC 842"). ASC 842 requires lessees to recognize right-of-use ("ROU") assets and lease payment liabilities on the balance sheet for leases representing the Company's right to use the underlying assets over the lease term. Each lease that is recognized on the balance sheet will be classified as either finance or operating, with such classification affecting the pattern and classification of expense recognition in the consolidated statements of operations and presentation within the statements of cash flows.

The Company adopted ASC 842 on January 1, 2019 using the modified retrospective method. The Company elected as part of its adoption to also use the optional transition methodology whereby previously reported periods continue to be reported in accordance with historical accounting guidance for leases that were in effect for those prior periods. Policy elections and practical expedients that the Company has implemented as part of adopting ASC 842 include (a) excluding from the balance sheet leases with terms that are less than or equal to one year, (b) for all existing asset classes that contain both lease and non-lease components, combining these components together and accounting for them as a single lease component, (c) the package of practical expedients, which among other things allows the Company to avoid reassessing contracts that commenced prior to adoption that were properly evaluated under legacy GAAP, and (d) excluding land easements, which were not accounted for under the previous leasing guidance, that existed or expired before adoption of ASC 842. The scope of ASC 842 does not apply to leases used in the exploration or use of minerals, oil, and natural gas.

The Company's adoption of ASC 842 resulted in an increase in other assets, accounts payable and accrued expenses, and other liabilities line items on the accompanying condensed consolidated balance sheets as a result of the additional ROU assets and related lease liabilities. Upon adoption on January 1, 2019, the Company recognized approximately $2.4 million in ROU assets and $4.3 million in liabilities for its operating leases. There was no cumulative effect to retained earnings upon the adoption of this guidance. See Note 14 for the new disclosures required by ASC 842.

Recently Issued Accounting Pronouncements: 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.

Change in estimate: Production taxes are comprised primarily of two elements: severance tax and ad valorem tax. During the three months ended March 31, 2019, the Company reduced its estimate for 2018 severance taxes. When preparing the 2018 severance tax return, the credit for ad valorem taxes was greater than originally estimated, resulting in a reduction of 2018 severance taxes. Based on this analysis, the Company's prior year accrual was reduced, resulting in an approximate $7.9 million reduction to our production taxes, which increased our operating income for the three months ended March 31, 2019 by a corresponding amount, or $0.03 per basic and diluted common share.

2. Property and Equipment

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

Oil and gas properties, full cost method:	As of June 30, 2019	As of December 31, 2018
Costs of proved properties:		
Producing and non-producing	$ 2,732,288	$ 2,385,958
Less, accumulated depletion and full cost ceiling impairments	(956,613)	(840,513)
Subtotal, proved properties, net	1,775,675	1,545,445
Costs of wells in progress	175,400	227,262
Costs of unproved properties and land, not subject to depletion:		
Lease acquisition and other costs	658,283	731,058
Land	9,395	9,395
Subtotal, unproved properties and land	667,678	740,453
Costs of other property and equipment:		
Other property and equipment	10,020	9,642
Less, accumulated depreciation	(5,139)	(4,102)
Subtotal, other property and equipment, net	4,881	5,540
Total property and equipment, net	$ 2,623,634	$ 2,518,700

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, 2019 and December 31, 2018, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no 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,	
	2019	2018	2019	2018
Capitalized overhead	$ 3,483	$ 3,280	$ 7,150	$ 6,393

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Depletion of oil and gas properties	$ 56,597	$ 40,927	$ 116,025	$ 77,029
Depreciation and accretion	1,430	950	2,920	1,929
Total DD&A Expense	$ 58,027	$ 41,877	$ 118,945	$ 78,958

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.

4. Asset Retirement Obligations

The Company recognizes obligations for its oil and natural gas operations for anticipated costs to remove and dispose of surface equipment, remediate the well, and reclaim 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, 2019
Asset retirement obligations, December 31, 2018	$ 51,746
Obligations incurred with development activities	1,278
Accretion expense	1,779
Obligations discharged with asset retirements and divestitures	(5,586)
Asset retirement obligation, June 30, 2019	$ 49,217
Less, current portion	(10,608)
Long-term portion	$ 38,609

5. 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, 2019, the terms of the Revolver provided for up to $1.5 billion in borrowings, an aggregate elected commitment of $550 million, and a borrowing base limitation of $700 million. As of June 30, 2019 and December 31, 2018, the outstanding principal balance was $165.0 million and $195.0 million, respectively. At June 30, 2019 and December 31, 2018, the Company had no letters of credit issued. The average annual interest rate for borrowings during the six months ended June 30, 2019 was 4.4%.

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. The next semi-annual redetermination is scheduled for November 2019. 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, limit our overall commodity derivative positions, and require the Company to maintain compliance with certain financial and liquidity ratio covenants. As of June 30, 2019, 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.

6. Notes Payable

2025 Senior Notes

In November 2017, the Company issued $550 million aggregate principal amount of 6.25% Senior Notes due 2025 (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%. Interest is payable on June 1 and December 1 of each year. The 2025 Senior Notes were issued pursuant to an indenture dated as of November 29, 2017. The associated expenses and underwriting discounts and commissions are amortized using the effective interest method at an effective interest rate of 6.6%.

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, 2019, none of the Company's subsidiaries met the criteria in the Indenture to be considered a guarantor of the 2025 Senior Notes.

As of June 30, 2019, the most recent compliance date, the Company was in compliance with the Indenture covenants and expects to remain in compliance throughout the next 12-month period.

7. 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 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, 2019 are summarized below:

Settlement Period	Derivative Instrument	Volumes (Bbls per day)	Weighted-Average Floor Price	Weighted-Average Ceiling Price
Crude Oil - NYMEX WTI				
July 1, 2019 - Dec 31, 2019	Collar	16,000	$ 55.00	$ 70.65

Settlement Period	Derivative Instrument	Volumes (MMBtu per day)	Weighted-Average Floor Price	Weighted-Average Ceiling Price
Natural Gas - NYMEX Henry Hub				
July 1, 2019 - Dec 31, 2019	Collar	30,000	$ 3.00	$ 3.50

Settlement Period	Derivative Instrument	Volumes (MMBtu per day)	Fixed Basis Difference
Natural Gas - CIG Rocky Mountain			
July 1, 2019 - Dec 31, 2019	Swap	30,000	$ (0.75)

Settlement Period	Derivative Instrument	Volumes (Bbls per day)	Weighted-Average Fixed Price
Propane - Mont Belvieu			
July 1, 2019 - Dec 31, 2019	Swap	2,000	$ 37.52

Offsetting of Derivative Assets and Liabilities

As of June 30, 2019 and December 31, 2018, 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 of the Company’s derivative contracts (in thousands):

		As of June 30, 2019		
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	$ 15,749	$ (3,688)	$ 12,061
Commodity derivative contracts	Noncurrent assets	—	—	—
Commodity derivative contracts	Current liabilities	3,688	(3,688)	—
Commodity derivative contracts	Noncurrent liabilities	$ —	$ —	$ —

		As of December 31, 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	$ 39,485	$ (4,579)	$ 34,906
Commodity derivative contracts	Noncurrent assets	—	—	—
Commodity derivative contracts	Current liabilities	4,579	(4,579)	—
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,	
	2019	2018	2019	2018
Realized gain (loss) on commodity derivatives	$ 3,304	$ (5,883)	$ 8,217	$ (7,955)
Unrealized gain (loss) on commodity derivatives	4,981	(8,411)	(22,845)	(12,120)
Total gain (loss)	$ 8,285	$ (14,294)	$ (14,628)	$ (20,075)

Realized gains and losses represent the monthly settlement of derivative contracts at their scheduled maturity date, net of the 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,	
	2019	2018	2019	2018
Monthly settlement	$ 3,962	$ (5,883)	$ 9,194	$ (7,955)
Premiums paid	(658)	—	(977)	—
Total realized gain (loss)	$ 3,304	$ (5,883)	$ 8,217	$ (7,955)

Credit-Related Contingent Features

As of June 30, 2019, all of the counterparties to the Company's derivative instruments were members of the Company's credit facility syndicate. The Company's obligations under the Revolver and its derivative contracts are secured by liens on substantially all of the Company's producing oil and gas properties.

8. 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 measurement includes asset retirement obligations. 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 reclamation 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 reclamation. 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 Note 4 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, 2019			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Commodity derivative asset	$ —	$ 12,061	$ —	$ 12,061
Commodity derivative liability	$ —	$ —	$ —	$ —

	Fair Value Measurements at December 31, 2018			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Commodity derivative asset	$ —	$ 34,906	$ —	$ 34,906
Commodity derivative liability	$ —	$ —	$ —	$ —

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, 2019, 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, 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 $499.1 million at June 30, 2019. The Company determined the fair value of its notes payable at June 30, 2019 by using observable market-based information for these debt instruments. The Company has classified the notes payable as Level 1.

9. Interest Expense

The components of interest expense are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Revolving credit facility	$ 2,132	$ 85	$ 4,305	$ 85
Notes payable	8,594	8,594	17,188	17,188
Amortization of issuance costs and other	851	1,113	1,648	2,000
Less: interest capitalized	(11,577)	(9,792)	(23,141)	(19,273)
Interest expense, net of amounts capitalized	$ —	$ —	$ —	$ —

10. Stock-Based Compensation

As of June 30, 2019, there were 10,500,000 common shares authorized for grant under the 2015 Equity Incentive Plan, of which 1,164,414 shares were available for future grant. The shares available for future grant exclude 1,973,768 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,	
	2019	2018	2019	2018
Stock options	$ 795	$ 1,195	$ 1,822	$ 2,398
Performance-vested stock units	1,258	1,173	2,329	2,029
Restricted stock units and stock bonus shares	1,766	1,400	4,081	2,736
Total stock-based compensation	$ 3,819	$ 3,768	$ 8,232	$ 7,163
Less: stock-based compensation capitalized	(677)	(622)	(1,407)	(1,221)
Total stock-based compensation expense	$ 3,142	$ 3,146	$ 6,825	$ 5,942

Stock options

No stock options were granted during the three and six months ended June 30, 2019 or 2018. The following table summarizes activity for stock options for the period presented:

	Number of Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Aggregate Intrinsic Value (thousands)
Outstanding, December 31, 2018	4,652,634	$ 10.06	6.4 years	$ 49
Granted	—	—		
Exercised	—	—		—
Expired	(12,000)	11.81		
Forfeited	(48,800)	7.46		
Outstanding, June 30, 2019	4,591,834	$ 10.09	5.9 years	$ 58
Outstanding, Exercisable at June 30, 2019	3,771,134	$ 10.30	5.7 years	$ 58

The following table summarizes information about issued and outstanding stock options as of June 30, 2019:

	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	3.1 years	35,000	$ 3.31	3.1 years
$5.00 - $6.99	683,000	6.29	5.8 years	433,600	6.25	5.1 years
$7.00 - $10.99	1,360,334	9.42	5.9 years	997,934	9.40	5.8 years
$11.00 - $13.46	2,513,500	11.57	5.9 years	2,304,600	11.56	5.9 years
Total	4,591,834	$ 10.09	5.9 years	3,771,134	$ 10.30	5.7 years

The estimated unrecognized compensation cost from stock options not vested as of June 30, 2019, which will be recognized ratably over the remaining vesting period, is as follows:

Unrecognized compensation (in thousands)	$ 2,484
Remaining vesting period	1.5 years

Restricted stock units and stock bonus awards

The following table summarizes activity for restricted stock units and stock bonus awards for the six months ended June 30, 2019:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Not vested, December 31, 2018	1,639,918	$ 8.07
Granted	1,535,984	4.87
Vested	(582,615)	8.62
Forfeited	(50,378)	6.40
Not vested, June 30, 2019	2,542,909	$ 6.04

The estimated unrecognized compensation cost from restricted stock units and stock bonus awards not vested as of June 30, 2019, which will be recognized ratably over the remaining vesting period, is as follows:

Unrecognized compensation cost (in thousands)	$ 12,065
Remaining vesting period	2.2 years

Performance-vested stock units

The Company has granted three 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. For the years prior to 2019, the PSUs will be settled in shares of the Company's common stock. For PSUs granted in 2019, if the PSUs vested are in an amount equal to or less than the target amount, they will be settled in shares of the Company's common stock. If the PSUs vested are in an amount greater than the target amount, then at the discretion of the Board of Directors, the value of the vested amount of PSUs in excess of the value of the PSU target amount may be paid wholly or partially in cash. All PSUs are settled at the end of the three-year performance cycle. Any PSUs that have not vested at the end of the applicable measurement period are forfeited.

Goal-Based PSUs - These PSUs are earned and vested after 2020 based on a discretionary assessment by the Compensation Committee. This assessment is anticipated to measure the performance of the Company and the executives over the defined vesting period. As vesting is based on the discretion of the Compensation Committee, we have not yet met the requirements of establishing an accounting grant date for them. This will occur when the Compensation Committee determines and communicates the vesting percentage 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, 2019, 274,898 Goal-Based PSUs had been awarded to certain executives.

Relative Total Shareholder Return ("Relative TSR") PSUs - The vesting criterion for the Relative TSR PSUs is based on a comparison of the Company's total shareholder return ("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.

Absolute Total Shareholder Return ("Absolute TSR") PSUs - The vesting criterion for the Absolute TSR PSUs is based on a comparison of the Company's TSR for the measurement period compared to the TSR goals outlined in the award. 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 assumptions used in valuing the TSR PSUs granted were as follows:

	Six Months Ended June 30,	
	2019	2018
Weighted-average expected term	2.9 years	2.8 years
Weighted-average expected volatility	48%	52%
Weighted-average risk-free rate	2.49%	2.41%

As of June 30, 2019, unrecognized compensation cost for TSR PSUs was $7.7 million and will be amortized through 2021. The following table summarizes activity for TSR PSUs for the six months ended June 30, 2019:

	Number of Units[1]	Weighted-Average Grant-Date Fair Value
Not vested, December 31, 2018	780,028	$ 11.73
Granted	918,842	5.74
Vested	—	—
Forfeited	—	—
Not vested, June 30, 2019	1,698,870	$ 8.49

[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.

11. 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,	
	2019	2018	2019	2018
Weighted-average shares outstanding — basic	243,404,917	242,255,724	243,348,141	242,005,211
Potentially dilutive common shares from:				
Stock options	13,719	421,316	12,611	387,634
TSR PSUs [1]	277,364	1,372,019	209,431	1,223,542
Restricted stock units and stock bonus shares	434,245	415,717	139,732	338,286
Weighted-average shares outstanding — diluted	244,130,245	244,464,776	243,709,915	243,954,673

[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,	
	2019	2018	2019	2018
Potentially dilutive common shares from:				
Stock options [1]	4,556,834	3,353,700	4,556,834	3,564,617
TSR PSUs [1,2]	773,954	—	1,233,375	—
Goal-Based PSUs [2,3]	274,898	281,872	274,898	281,872
Restricted stock units and stock bonus shares [1]	695,353	2,772	704,948	10,005
Total	6,301,039	3,638,344	6,770,055	3,856,494

[1] Potential common shares excluded from the 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 the 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.

12. 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.

The effective combined U.S. federal and state income tax rates for the three and six months ended June 30, 2019 were 25% and 26%, respectively. For the three and six months ended June 30, 2018, the effective tax rates were 6% and 7%, respectively. The effective tax rates for the three and six months ended June 30, 2019 differed from the statutory rate primarily due to state income taxes, non-deductible expenses, and tax deficiencies recognized in connection with the vesting of stock awards. The 2018 rates differed from the statutory rates due primarily to the release of valuation allowances previously recorded against deferred tax assets.

As of June 30, 2019, 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. No significant uncertain tax positions were identified as of any date on or before June 30, 2019. The Company's policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. As of June 30, 2019, 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, 2019, the Company believes it will be able to generate sufficient future positive 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. In addition to the future positive net income, the temporary deferred tax liabilities exceed the deferred tax assets, resulting in the ability to utilize all deferred tax assets to offset future taxable income resulting from the reversal of the deferred tax liabilities.

13. 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):	2019	2018	2019	2018
Oil	$ 132,098	$ 114,857	$ 279,178	$ 231,061
Natural Gas and NGLs	30,504	32,230	72,879	63,259
	$ 162,602	$ 147,087	$ 352,057	$ 294,320

14. Leases

The Company evaluates contractual arrangements at inception to determine if the agreement is a lease or contains an identifiable lease component as defined by ASC 842. When evaluating contracts to determine appropriate classification and recognition under ASC 842, significant judgment may be necessary to determine, among other criteria, if an embedded leasing arrangement exists, the length of the term, classification as either an operating or financing lease, whether renewal or termination options are reasonably certain to be exercised, and future lease payments to be included in the initial measurement of the ROU asset. Certain assumptions and judgments made by the Company when evaluating contracts that meet the definition of a lease under ASC 842 include:

- Discount Rate - Unless implicitly defined, the Company will determine the present value of future lease payments using an estimated incremental secured borrowing rate based on a yield curve analysis that factors in certain assumptions, including the term of the lease and credit rating of the Company at lease commencement.
- Lease Term - The Company evaluates each contract containing a lease arrangement at inception to determine the length of the lease term when recognizing a ROU asset and corresponding lease liability. When determining the lease term, options available to extend or early terminate the arrangement are evaluated and included when it is reasonably certain these options will be exercised. There are no available options to extend that the Company is reasonably certain to exercise.

Currently, the Company has operating leases for asset classes that include office space, drilling rigs, and equipment rentals primarily used in development and field operations. The Company has financing leases for vehicles. We have provided a residual value guarantee for our vehicle leases. Certain leases also contain optional extension periods that allow for lease terms to be extended for up to an additional 5 years.

Costs associated with the Company's operating leases are either expensed or capitalized depending on how the underlying asset is utilized. For example, costs associated with drilling rigs are capitalized as part of the development of the Company's oil and gas properties. Refer to the Company's 2018 Form 10-K for additional information on its accounting policies for oil and gas development and producing activities. When calculating the Company's ROU asset and liability, the Company considers all the necessary payments made or that are expected to be made upon commencement of the lease. Excluded from the initial measurement are certain variable lease payments.

The Company's total lease costs were as follows (in thousands):

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
Finance lease cost:		
Amortization of ROU assets	$ 63	$ 123
Interest on lease liabilities	7	15
Operating lease cost	1,173	1,777
Short-term lease cost [1]	27,783	69,846
Total Lease Cost	$ 29,026	$ 71,761

[1] Costs associated with short-term lease agreements relate primarily to operational activities where underlying lease terms are less than or equal to one year. These costs primarily include drilling activities and field equipment rentals. It is expected that this amount will fluctuate primarily with the number of drilling rigs that the Company is operating under short-term agreements.

Other information related to the Company's leases is as follows (in thousands, except lease terms and discount rates):

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from operating leases	$ 1,173	$ 1,777
Financing cash flows from finance leases	47	105
ROU assets obtained in exchange for new finance lease liabilities	43	138
ROU assets obtained in exchange for new operating lease liabilities	4,006	8,538

	As of June 30, 2019
Weighted-average remaining lease term - finance leases	3.0 years
Weighted-average remaining lease term - operating leases	2.0 years
Weighted-average discount rate - finance leases	4.75%
Weighted-average discount rate - operating leases	4.75%

As of June 30, 2019 and through the date of issuance of these financial statements, the Company has no material lease arrangements which are scheduled to commence in the future. Maturities for the Company's operating and finance lease liabilities included on the accompanying condensed balance sheets as of June 30, 2019 were as follows (in thousands):

Year	Finance Leases	Operating Leases
2019	$ 94	$ 2,471
2020	188	4,684
2021	215	1,550
2022	185	500
2023	25	—
Thereafter	—	—
Total lease payments	$ 707	$ 9,205
Less imputed interest	(57)	(420)
Total lease liability	$ 650	$ 8,785

As of December 31, 2018, minimum future contractual payments were as follows (in thousands):

Year	Rig Contracts	Capital Leases	Operating Leases
2019	$ 11,102	$ 183	$ 896
2020	—	186	916
2021	—	204	913
2022	—	167	500
2023	—	—	—
Thereafter	—	—	—

Amounts recorded on the Company's accompanying condensed balance sheets were as follows (in thousands):

As of June 30, 2019	Financing Leases	Operating Leases
Other property and equipment, net	$ 755	$ —
Other assets	—	7,161
Accounts payable and accrued expenses	161	4,629
Other liabilities	489	4,156
	$ 650	$ 8,785

15. Other Commitments and Contingencies

Oil Commitments

The Company has entered into firm sales agreements for its oil production with four counterparties. Deliveries under the sales agreements have commenced. 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, excluding the contingent commitment described below, are as follows:

Year ending December 31, 2019	Oil (MBbls)
Remainder of 2019	2,605
2020	4,003
2021	1,672
Total	8,280

During the second quarter of 2019, 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. However, this cannot be guaranteed.

In the third quarter of 2019, the Company entered into an agreement for the transportation of additional oil production. Under this new agreement, which is a collaboration with several other parties, our baseline volume commitment is for 15,000 Bbls per day for a seven year term. Deliveries under this sales agreement are expected to commence in the third quarter of 2019, but the initial obligation may be reduced as the existing pipeline is currently under allocation. If we are unable to fulfill all of our minimum volume commitment and such commitment is not sufficiently reduced by offsetting production delivered by other parties, we may be required to pay demand charges on any unfulfilled capacity.

Natural Gas Commitments

In collaboration with several other producers and DCP Midstream, LP ("DCP Midstream"), we entered into two facilities expansion agreements with DCP Midstream, LP ("DCP Midstream") to expand and improve its natural gas gathering pipelines and processing facilities. DCP Midstream completed and turned on line the first of the two 200 MMcf per day plants in August 2018. The second plant is currently being commissioned and is expected to be placed fully into service during the third quarter of 2019. We are bound to the volume requirements in these agreements on the first day of the calendar month following the actual in-service date of the relevant plant. Both agreements require baseline volume commitments, consisting of our gross wellhead volume delivered in November 2016 to DCP Midstream, and incremental wellhead volume commitments of 46.4 MMcf per day and 43.8 MMcf per day for the first and second agreements, respectively, for 7 years. If we are unable to fulfill all of our contractual obligations and our obligations are not sufficiently reduced by the collective volumes delivered by other producers, we may be required to pay penalties or damages pursuant to these agreements. During the second quarter of 2019, 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. We are also required for the first three years of the contracts to guarantee a certain target profit margin to DCP Midstream on these incremental volumes. Payments made to date for such quantities have not been significant.

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.

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:	2019	2018
Interest paid	$ 21,139	$ 17,448
Non-cash investing and financing activities:		
Accrued well costs as of period end	$ 52,531	$ 75,705
Asset retirement obligations incurred with development activities	1,278	473
Asset retirement obligations assumed with acquisitions	—	5
Obligations discharged with asset retirements and divestitures	$ (5,586)	$ (5,964)
Net changes in operating assets and liabilities:		
Accounts receivable	$ 33,541	$ 2,797
Accounts payable and accrued expenses	(685)	(42)
Revenue payable	(1,208)	5,377
Production taxes payable	(13,849)	8,199
Other	634	88
Changes in operating assets and liabilities	$ 18,433	$ 16,419

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, 2019 and its results of operations for the three and six months ended June 30, 2019 and 2018. It should be read in conjunction with 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, 2018 filed with the SEC on February 20, 2019. 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 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. Our oil and natural gas activities are focused in the Wattenberg Field, an area that covers the western flank of the D-J Basin. All of our activities and planned drilling locations are located in Weld County, Colorado, and 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 90% of our proved developed reserves and anticipate operating a majority of our future net drilling locations.

Market Conditions

Market prices for our products significantly impact our revenues, net income, cash flow, future growth, and carrying value of our oil and gas properties. 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 four years.

	Year Ended December 31,			
	2018	2017	2016	2015
Average NYMEX prices				
Oil (per Bbl)	$ 64.94	$ 50.93	$ 43.20	$ 48.73
Natural gas (per Mcf)	$ 3.09	$ 3.00	$ 2.52	$ 2.58

For the periods presented in this report, the following table presents the average NYMEX prices as well as the differential between the NYMEX prices and the prices realized by us.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Oil (NYMEX-WTI)				
Average NYMEX Price	$ 59.78	$ 68.03	$ 57.31	$ 65.46
Realized Price *	52.75	61.22	50.32	58.48
Differential *	$ (7.03)	$ (6.81)	$ (6.99)	$ (6.98)
Natural Gas (NYMEX-Henry Hub)				
Average NYMEX Price	$ 2.64	$ 2.80	$ 2.89	$ 2.90
Realized Price *	1.58	1.64	2.04	1.87
Differential *	$ (1.06)	$ (1.16)	$ (0.85)	$ (1.03)
NGL Realized Price	$ 9.39	$ 17.65	$ 10.95	$ 18.30

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

Market conditions in the Wattenberg Field can require us to sell oil at prices less than the prices posted by the NYMEX. The differential between the prices actually received by us and the published indices reflects deductions imposed upon us by the purchasers for location and quality adjustments. To the extent the Company's oil production exceeded its firm sales commitments during the six months ended June 30, 2019, the surplus oil production was sold at a reduced differential as compared to our committed volumes.

Our natural gas sales tend to trend 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 2019 decreased to $1.95 from $2.95 in the first quarter of 2019, resulting in the basis difference for CIG to NYMEX-Henry Hub increasing from $0.20 to $0.69.

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, 2019, 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, 2019:

Vertical Wells

Operated Wells		Non-Operated Wells		Totals	
Gross	Net	Gross	Net	Gross	Net
512	495	165	44	677	539

Horizontal Wells

Operated Wells		Non-Operated Wells		Totals	
Gross	Net	Gross	Net	Gross	Net
433	409	321	57	754	466

In addition to the producing wells summarized in the preceding table, as of June 30, 2019, we were the operator of 122 gross (115 net) horizontal wells in progress. As of June 30, 2019, we are participating in 39 gross (5 net) non-operated horizontal wells in progress.

As we develop our acreage through horizontal drilling, we have an active program for the remediation and reclamation of the vast majority of the operated vertical wellbores. During the six months ended June 30, 2019, we reclaimed 58 wells and returned the associated acreage to the property owners.

Drilling and Completion Operations

Our drilling and completion schedule drives our production forecast. 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 and operating conditions are favorable, we may choose to accelerate drilling and completion activities, assuming adequate gas processing capacity is available at the time.

During the six months ended June 30, 2019, we drilled 59 operated horizontal wells and turned 58 operated horizontal wells to sales. As of June 30, 2019, the Company had 12 gross (11 net) wells that were drilled and completed, but not producing. These wells are expected to be turned to sales during the third quarter. As of June 30, 2019, we are the operator of 122 gross (115 net) horizontal wells in progress. All of this activity was funded through cash flows from operations. For 2019 as a whole, we expect to drill 99 gross (90 net) operated horizontal wells and complete approximately 68 gross (62 net) operated horizontal wells with mid-length and long laterals targeting the Codell and Niobrara formations.

For the six months ended June 30, 2019, we participated in the completion of 8 gross (0.4 net) non-operated horizontal wells. As of June 30, 2019, we are participating in 39 gross (5 net) non-operated horizontal wells in progress.

Production

For the three months ended June 30, 2019, our average daily production increased to 60,833 BOED as compared to 47,646 BOED for the three months ended June 30, 2018. During the first six months of 2019, our average net daily production was 63,288 BOED. By comparison, during the six months ended June 30, 2018, our average production rate was 46,528 BOED. As of June 30, 2019, approximately 98% of our daily production was from horizontal wells.

Gas gathering and processing constraints have continued to limit production growth and ultimately restrict well performance within the DJ Basin. DCP Midstream, our primary gas gathering and processing service provider, has maintained a system-wide producer allocation which is intended to stabilize line pressures. In addition, significant planned and unplanned downtime reduced system capacity throughout the second quarter and first half of 2019. This resulted in consistently high line pressures, restricting our ability to maintain consistent production levels, and we have continued to shut-in and curtail our production. The aggregate volumes currently shut-in are approximately 25,000 BOED with an approximate 33% oil cut. This volume and oil cut is based upon what the wells were producing at the time they were shut in. In response to these conditions, we planned our 2019 budgeted activity to adjust the cadence of both drilling and completion operations and reduced our year-over-year capital expenditures budget by approximately 35% in order to optimize capital efficiency.

Strategy

Our primary objective has been to enhance shareholder value by increasing our net asset value, net reserves, and cash flow through acquisitions and development of oil and gas properties. In light of current midstream constraints in the D-J basin and the current commodity price environment, we have increased our emphasis on financial discipline to maximize capital efficiency. This along with other key elements of our business strategy are described below:

- *Maximize shareholder value and maintain financial discipline with a goal of establishing free cash flow at the corporate level.* We have continued to align our capital expenditures with our cash flows by adjusting our operating activities depending on commodity prices and infrastructure capacity. We strive to be a cost-efficient operator and to maintain a relatively low utilization of debt. Towards this goal, we have reduced our operational activities during 2019 as further described below in *Significant Developments*.

- *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 in the Wattenberg Field. Focusing our operations in this area leverages our management, technical, and operational experience in the basin.

- *Develop and exploit existing oil and gas properties.* A 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 safest and most efficient and economical 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 primarily 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, coupled with production results, to implement a continuous improvement philosophy in optimizing the value per acre of our leasehold throughout our development program.

- *Control and reduce emissions from our drilling and completion activities and production facilities*. We place high importance on achieving compliance with all applicable air quality rules and regulations and the further reduction of emissions continues to be a top priority. To minimize emissions, we employ best management practices such as contracting an electric hydraulic stimulation fleet, utilizing all available direct pipeline take-away access and pneumatic actuated instrument devices, and working with suppliers to deploy diesel engines that meet the U.S. Environmental Protection Agency Tier 4 standard. We control emissions and minimize flaring of gas during the drilling and completion process. We use additional vapor recovery equipment during production for further emissions reduction. 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).

- *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. Such practices include building our infrastructure out ahead of operations to minimize traffic, working with our service providers to minimize dust and lighting issues, and constructing sound walls to minimize noise. We value our positive relationship with local governmental 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, including midstream availability, permit. Our high degree of operational control, as well as our focus on operating efficiencies that provide short return on investment cycle times, is central to our operating strategy.

- *Acquire and develop assets near established infrastructure*. We have historically targeted acquisitions of contiguous acreage to focus our development plans on areas where technically-capable, financially-stable midstream companies have existing assets and plans for additional investment. We continue to work collaboratively with these companies to proactively identify expansion opportunities that complement our current development plans. This enables the use of gathering pipelines, which reduces the need to use trucks and thereby reduces traffic and noise.

Significant Developments

Operations

In May 2019, we released our completion crew. In our continuing effort to reduce air emissions, we plan to test an electric hydraulic stimulation fleet beginning in the third quarter of 2019. Furthermore, we will release one of our drilling rigs in the third quarter of 2019 and expect to operate one drilling rig for the remainder of the year and into 2020.

Legislative Matters

New legislation governing oil and gas development in Colorado, referred to as SB19-181, and titled "Protect Public Welfare Oil and Gas Operations," became law in April 2019. Among other things, SB19-181 provides that local governments have land use authority to regulate the siting of oil and gas locations, states that it is in the public interest to regulate the development of oil and gas resources in a manner that protects public health, safety, and welfare, including protection of the environment and wildlife resources, and modifies requirements related to statutory pooling. There is ongoing rulemaking associated with this legislation that will affect the implementation and effect of the law. SB19-181 could have a variety of effects on our operations, but we believe that some of these impacts may be mitigated by the fact that the statute places a significant emphasis on local control of oil and gas regulatory matters, and all of our planned future development activities are in Weld County, a jurisdiction in which there is a strong support of the oil and gas industry.

Revolving Credit Facility

In April 2019, the lenders under the Revolver completed their semi-annual redetermination of our borrowing base. The borrowing base was increased from $650 million to $700 million, and we increased our aggregate elected commitment from $500 million to $550 million.

Trends and Outlook

NYMEX-WTI oil traded at $45.15 per Bbl on December 28, 2018, but increased approximately 29% as of June 28, 2019 to $58.20. NYMEX-Henry Hub natural gas traded at $3.25 per Mcf on December 28, 2018, but declined approximately 26% as of June 28, 2019 to $2.42. Although NYMEX-WTI oil prices increased over the first half in 2019, 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 the exploration and replacement of 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 shut-in as non-commercial, and (vi) cause ceiling test impairments.

We continually focus on managing drilling and completion costs through a combination of well design optimization, reductions in the average days to drill, and employment of current technological advancements. This focus on cost management helps support well-level economics under varying oil and natural gas pricing environments.

Multiple midstream companies that operate natural gas processing facilities and gathering pipelines in the Wattenberg Field continue to make significant capital investments to increase the capacity of their systems. Until such time that these facilities are operational, our production has been, and most likely will continue to be, adversely impacted by a lack of available processing capacity.

To address the growing volumes of natural gas production in the D-J Basin, DCP Midstream has been developing multiple projects including new processing plants, an expansion of its low- and high-pressure gathering systems, additional compression, and plant bypass infrastructure. Most notably, in collaboration with DCP Midstream, we and several other producers 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. DCP Midstream's second expansion under this arrangement is the O'Connor processing complex, which is currently being expanded by 200 MMcf per day of processing capacity along with the ability to bypass an incremental 100 MMcf per day. This processing expansion is expected to be placed in service during the third quarter of 2019. DCP Midstream has also recently announced an offload agreement with Western Midstream Partners, LP for up to 225 MMcf per day of incremental processing capacity in 2020 at Western’s facility. Further, DCP Midstream has secured the land and permits for the development of another facility ("Bighorn"), where DCP Midstream could add processing capacity of up to 1 Bcf per day, including bypass.

As a result of the current lack of gas processing capacity, a system-wide volume allocation limiting each producer’s throughput was implemented in November 2017 and has not been lifted. In an effort to pace development with midstream capacity, we will release one of our two drilling rigs during third quarter of 2019 and will run one rig for the remainder of the year and into 2020. Additionally, we dropped our sole completion crew during the second quarter of 2019. As gas processing capacity increases, we plan to bring back one completion crew in the third quarter of 2019. We will be utilizing an electric fleet upon the crew's return to service. In our continuing effort to reduce our emissions, we want to test the efficiency of the electric fleet for its possible usage in 2020.

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 continue to be expanded, we have experienced and may continue to experience some delays in placing our pads on production.

Oil pipeline takeaway capacity utilization has increased as oil production in the basin has grown. However, capacity decreased in the second quarter of 2019 when a portion of a third-party crude oil pipeline system was converted to NGL service. To address the projected demand for additional capacity, several open seasons have been announced for the expansion of certain interstate pipelines servicing the Wattenberg Field. We continuously strive to reduce the negative differential 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."

For 2019, we expect to drill 99 gross operated horizontal wells (59 of which were drilled through June 30, 2019) with mostly mid-length and long laterals targeting the Codell and Niobrara zones. We anticipate that total capital expenditures, including operated drilling and completion costs, limited leasehold acquisition costs and selected non-operated drilling and completion costs, will be between $425 million and $450 million and will lead to an increase in production and associated proved developed producing reserves. Our current estimate is that full-year 2019 production will average between 63,000 BOED and 66,000 BOED with oil making up 42% to 45% 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, 2019 compared to the three months ended June 30, 2018

For the three months ended June 30, 2019, we reported net income of $54.5 million compared to net income of $49.6 million during the three months ended June 30, 2018. Net income per basic and diluted share was $0.22 for the three months ended June 30, 2019 compared to net income per basic and diluted share of $0.20 for the three months ended June 30, 2018.

Oil, Natural Gas, and NGL Production and Revenues - For the three months ended June 30, 2019, we recorded total oil, natural gas, and NGL revenues of $162.6 million compared to $147.1 million for the three months ended June 30, 2018, an increase of $15.5 million or 11%. The following table summarizes key production and revenue statistics:

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Percentage Change
Production:			
Oil (MBbls) [1]	2,441	1,846	32 %
Natural Gas (MMcf) [2]	11,905	8,987	32 %
NGLs (MBbls) [1]	1,111	992	12 %
MBOE [3]	5,536	4,336	28 %
BOED [4]	60,833	47,646	28 %
Revenues (in thousands):			
Oil	$ 132,098	$ 114,857	15 %
Natural Gas	20,069	14,714	36 %
NGLs	10,435	17,516	(40)%
	$ 162,602	$ 147,087	11 %
Average sales price:			
Oil [5]	$ 52.75	$ 61.22	(14)%
Natural Gas [5]	1.58	1.64	(4)%
NGLs	9.39	17.65	(47)%
BOE [5]	$ 28.53	$ 33.50	(15)%

[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, 2019 averaged 60,833 BOED, an increase of 28% over average production of 47,646 BOED in the three months ended June 30, 2018. From June 30, 2018 to June 30, 2019, our well count increased by 165 net horizontal wells, growing our reserves and daily production totals. The 28% increase in production resulted in an increase in revenues which was partially offset by the 15% decrease in average sales prices.

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

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018
Production costs	$ 12,963	$ 11,433
Workover	267	179
Total LOE	$ 13,230	$ 11,612
Per BOE:		
Production costs	$ 2.34	$ 2.64
Workover	0.05	0.04
Total LOE	$ 2.39	$ 2.68

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, 2019, we experienced increased production expense compared to the three months ended June 30, 2018 due to an increase in net operated wells.

Transportation and gathering - Transportation and gathering costs were $4.7 million, or $0.84 per BOE, for the three months ended June 30, 2019, compared to $1.9 million, or $0.43 per BOE, for the three months ended June 30, 2018. Coinciding with the increase in its production in 2019, the Company has increased the volume 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 $13.2 million, or $2.38 per BOE, for the three months ended June 30, 2019, compared to $15.1 million, or $3.47 per BOE, during the three months ended June 30, 2018. As a percentage of revenues, production taxes were 8.1% and 10.2% for the three months ended June 30, 2019 and 2018, respectively.

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

	Three Months Ended June 30,	
(in thousands)	2019	2018
Depletion of oil and gas properties	$ 56,597	$ 40,927
Depreciation and accretion	1,430	950
Total DD&A	$ 58,027	$ 41,877
DD&A expense per BOE	$ 10.48	$ 9.66

For the three months ended June 30, 2019, DD&A was $10.48 per BOE compared to $9.66 per BOE for the three months ended June 30, 2018. 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, whereby the ratio of production volumes for the quarter to the beginning of the quarter estimated total reserves determines 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)	2019	2018
Total Non-Cash G&A	$ 3,819	$ 3,768
Total Cash G&A	8,932	8,953
Capitalized G&A Costs	(3,508)	(3,315)
Total G&A Expense	$ 9,243	$ 9,406
Non-Cash G&A Expense	$ 3,142	$ 3,146
Cash G&A Expense	6,101	6,260
Total G&A Expense	$ 9,243	$ 9,406
Non-Cash G&A Expense per BOE	$ 0.57	$ 0.73
Cash G&A Expense per BOE	1.10	1.44
G&A Expense per BOE	$ 1.67	$ 2.17

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 $9.2 million for the second quarter of 2019 were 2% lower than G&A for the same period of 2018.

Our G&A expense for the three months ended June 30, 2019 includes stock-based compensation of $3.1 million compared to $3.1 million for the three months ended June 30, 2018.

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.

Commodity derivative gains (losses) - As more fully described in Item 1. Financial Statements – Note 7, *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, 2019, we realized a settlement gain of $3.3 million. For the prior comparable period, we realized a settlement loss of $5.9 million.

In addition, for the three months ended June 30, 2019, we recorded an unrealized gain of $5.0 million to recognize the mark-to-market change in fair value of our commodity contracts. By comparison, in the three months ended June 30, 2018, we reported an unrealized loss of $8.4 million. Unrealized gains and losses are non-cash items.

Income taxes - As more fully described in Item 1. Financial Statements – Note 12, *Income Taxes*, we reported income tax expense of $18.2 million for the three months ended June 30, 2019 as compared to $3.3 million for the comparable prior year period. The effective tax rate for the three months ended June 30, 2018 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, 2019 compared to the six months ended June 30, 2018

For the six months ended June 30, 2019, we reported net income of $104.2 million compared to net income of $115.4 million during the six months ended June 30, 2018. Net income per basic and diluted share was $0.43 for the six months ended June 30, 2019 compared to net income per basic and diluted share of $0.48 and $0.47, respectively, for the six months ended June 30, 2018.

Oil, Natural Gas, and NGL Production and Revenues - For the six months ended June 30, 2019, we recorded total oil, natural gas, and NGL revenues of $352.1 million compared to $294.3 million for the six months ended June 30, 2018, an increase of $57.7 million or 20%. The following table summarizes key production and revenue statistics:

	Six Months Ended June 30,		Percentage
	2019	2018	Change
Production:			
Oil (MBbls)	5,408	3,887	39 %
Natural Gas (MMcf)	23,296	16,706	39 %
NGLs (MBbls)	2,165	1,750	24 %
MBOE	11,455	8,422	36 %
BOED	63,288	46,528	36 %
Revenues (in thousands):			
Oil	$ 279,178	$ 231,061	21 %
Natural Gas	49,173	31,231	57 %
NGLs	23,706	32,028	(26)%
	$ 352,057	$ 294,320	20 %
Average sales price:			
Oil	$ 50.32	$ 58.48	(14)%
Natural Gas	2.04	1.87	9 %
NGLs	10.95	18.30	(40)%
BOE	$ 29.97	$ 34.50	(13)%

Net oil, natural gas, and NGL production for the six months ended June 30, 2019 averaged 63,288 BOED, an increase of 36% over average production of 46,528 BOED in the six months ended June 30, 2018. From June 30, 2018 to June 30, 2019, our well count increased by 165 net horizontal wells, growing our reserves and daily production totals. The 36% production resulted in an increase in revenues which was partially offset by the 13% decrease in average sales prices.

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

	Six Months Ended June 30,	
	2019	2018
Production costs	$ 30,244	$ 19,147
Workover	346	361
Total LOE	$ 30,590	$ 19,508
Per BOE:		
Production costs	$ 2.64	$ 2.27
Workover	0.03	0.04
Total LOE	$ 2.67	$ 2.31

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, 2019, we experienced increased production expense compared to the six months ended June 30, 2018 primarily due to an increase in net operated wells.

Transportation and gathering - Transportation and gathering costs were $8.7 million, or $0.76 per BOE, for the six months ended June 30, 2019, compared to $3.7 million, or $0.44 per BOE, for the six months ended June 30, 2018. Coinciding with the increase in its production in 2019, the Company has increased the volume 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. During the three months ended March 31, 2019, the Company reduced its estimate for 2018 severance taxes. When preparing the 2018 severance tax return, we determined that the credit for ad valorem taxes would be greater than originally estimated, resulting in a reduction of 2018 severance taxes. Based on this analysis, the Company's prior year accrual was reduced, resulting in an approximate $7.9 million reduction to our production taxes. Production taxes were $20.3 million, or $1.77 per BOE, for the six months ended June 30, 2019, compared to $28.5 million, or $3.38 per BOE, for the six months ended June 30, 2018. Taxes tend to increase or decrease primarily based on the value of production sold. As a percentage of revenues, production taxes were 5.8% and 9.7% for the six months ended June 30, 2019 and 2018, respectively, with the 2019 period reflecting the effect of the change in estimate.

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

	Six Months Ended June 30,	
(in thousands)	2019	2018
Depletion of oil and gas properties	$ 116,025	$ 77,029
Depreciation and accretion	2,920	1,929
Total DD&A	$ 118,945	$ 78,958
DD&A expense per BOE	$ 10.38	$ 9.38

For the six months ended June 30, 2019, DD&A was $10.38 per BOE compared to $9.38 per BOE for the six months ended June 30, 2018. 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, whereby the ratio of production volumes for the quarter to the beginning of the quarter estimated total reserves determines 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)	2019	2018
Total Non-Cash G&A	$ 8,232	$ 7,163
Total Cash G&A	17,682	18,299
Capitalized G&A Costs	(7,202)	(6,456)
Total G&A Expense	$ 18,712	$ 19,006
Non-Cash G&A Expense	$ 6,825	$ 5,942
Cash G&A Expense	11,887	13,064
Total G&A Expense	$ 18,712	$ 19,006
Non-Cash G&A Expense per BOE	$ 0.60	$ 0.71
Cash G&A Expense per BOE	1.04	1.55
G&A Expense per BOE	$ 1.64	$ 2.26

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 $18.7 million for the six months ended June 30, 2019 were 2% lower than G&A for the same period of 2018. Cash G&A for the six months ended June 30, 2018 was elevated by expenses incurred in support of Colorado oil and gas legislative activities during the second quarter of 2018.

Our G&A expense for the six months ended June 30, 2019 includes stock-based compensation of $6.8 million compared to $5.9 million for the six months ended June 30, 2018.

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, 2018 to the six months ended June 30, 2019 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 7, *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, 2019, we realized a settlement gain of $8.2 million. For the prior comparable period, we realized a settlement loss of $8.0 million, net of previously incurred premiums attributable to the settled commodity contracts.

In addition, for the six months ended June 30, 2019, we recorded an unrealized loss of $22.8 million to recognize the mark-to-market change in fair value of our commodity contracts. In comparison, in the six months ended June 30, 2018, we reported an unrealized loss of $12.1 million. Unrealized losses are non-cash items.

Income taxes - We reported income tax expense of $36.3 million for the six months ended June 30, 2019 as compared to $9.2 million of income tax expense for the comparable prior year period. The effective tax rate for the six months ended June 30, 2018 differed from the statutory rates due primarily to the release of valuation allowances previously recorded against deferred tax assets.

Liquidity and Capital Resources

Historically, our primary sources of capital have been net cash provided by cash flow from operations, the sale of equity and debt securities, borrowings under revolving credit facilities, and proceeds from the sale of properties. 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, 2019, our cash provided by operating activities of $301.6 million exceeded the $276.1 million spent on drilling and completion 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, including midstream availability, 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, 2019, we had cash and cash equivalents of $27.8 million, $550.0 million outstanding on our 2025 Senior Notes, and a $165.0 million balance outstanding under our revolving credit facility. Our sources and (uses) of funds for the six months ended June 30, 2019 and 2018 are summarized below (in thousands):

	Six Months Ended June 30,	
	2019	2018
Net cash provided by operations	$ 301,583	$ 235,762
Capital expenditures	(304,545)	(255,712)
Net cash provided by other investing activities	12,802	766
Net cash provided by (used in) equity financing activities	(1,126)	3,025
Net cash provided by (used in) debt financing activities	(30,484)	22,857
Net increase (decrease) in cash and cash equivalents	$ (21,770)	$ 6,698

Net cash provided by operating activities was $301.6 million and $235.8 million for the six months ended June 30, 2019 and 2018, respectively. The increase in cash from operating activities reflects the growth in our production.

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 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.

In April 2019, the borrowing base was increased from $650 million to $700 million, and our elected commitment amount was increased to $550 million from $500 million. As of June 30, 2019, there was a $165.0 million principal balance outstanding and no letters of credit outstanding, leaving $385.0 million available to us for future borrowings. The next semi-annual redetermination is scheduled for November 2019. 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 due 2025 (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%. Interest is payable on June 1 and December 1 of each year.

The 2025 Senior Notes were issued pursuant to an indenture dated as of November 29, 2017 (the "Indenture") and will be guaranteed on a senior unsecured basis by the Company's existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under the Revolver. The 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 $202.1 million and $231.2 million for the six months ended June 30, 2019 and 2018, respectively. The following table summarizes our capital expenditures for oil and gas properties (in thousands):

	Six Months Ended June 30,	
	2019	2018
Capital expenditures for drilling and completion activities	$ 202,119	$ 231,196
Acquisitions of oil and gas properties and leasehold[1]	219	16,402
Capitalized interest, capitalized G&A, and other	32,489	26,753
Accrual basis capital expenditures[2]	$ 234,827	$ 274,351

[1] Acquisitions of oil and gas properties and leasehold reflects the full purchase price of the relevant acquisitions, including non-cash additions for liabilities assumed in the transaction such as asset retirement obligations.
[2] 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, 2019, we drilled 59 operated horizontal wells and turned 58 operated horizontal wells to sales. As of June 30, 2019, the Company had 12 gross (11 net) wells that were drilled and completed, but not producing. These wells are expected to be turned to sales during the third quarter. As of June 30, 2019, we are the operator of 122 gross (115 net) horizontal wells in progress. All of the wells in progress at June 30, 2019 are scheduled to commence production before December 31, 2020. All of our drilling and completion activity was funded through cash flows from operations.

For the six months ended June 30, 2019, we participated in 47 gross (5 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, acquisitions and divestitures, 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 acquisitions that we may complete during 2019.

We anticipate that our full-year 2019 capital expenditures, including operated drilling and completion costs, limited leasehold acquisition costs and selected non-operated drilling and completion costs, will be between $425 million and $450 million. However, should commodity prices and/or economic conditions change, we can reduce or accelerate (subject to midstream constraints) 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, 2019, we had open positions covering 2.9 million barrels of oil and 11.0 Bcf 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, 2019, we reported an unrealized commodity activity loss of $22.8 million. Unrealized losses are non-cash items. We also reported a realized gain of $8.2 million, representing the settlement of commodity contracts settled during the period.

At June 30, 2019, we estimated that the fair value of our various commodity derivative contracts was a net asset of $12.1 million. See Item 1. Financial Statements – Note 8, *Fair Value Measurements*, for a description of the methods we use to estimate the fair values of commodity derivative instruments.

Non-GAAP Financial Measure

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 that 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 (in thousands):

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Adjusted EBITDA:				
Net income	$ 54,468	$ 49,624	$ 104,219	$ 115,420
Depreciation, depletion, and accretion	58,027	41,877	118,945	78,958
Stock-based compensation expense	3,142	3,146	6,825	5,942
Mark-to-market of commodity derivative contracts:				
Total loss on commodity derivatives contracts	(8,285)	14,294	14,628	20,075
Cash settlements on commodity derivative contracts	3,089	(4,566)	7,715	(6,121)
Cash premiums paid for commodity derivative contracts	(658)	—	(977)	—
Interest income	(92)	(5)	(161)	(14)
Income tax expense	18,237	3,347	36,271	9,158
Adjusted EBITDA	$ 127,928	$ 107,717	$ 287,465	$ 223,418

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 20, 2019 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 capital expenditures and projects, the adequacy and nature of future sources of financing, midstream capacity issues and planned capacity expansion projects, future production (including production relative to volume commitments) and reserves, covenant compliance, and the implementation and effects of SB19-181 and our responses thereto.

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, 2018 filed with the SEC on February 20, 2019 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;
- the effects of, changes in and the costs of compliance with federal, state, and local regulations applicable to our business, including those related to hydraulic stimulation and SB19-181;
- operating hazards that adversely affect our ability to conduct business;
- uncertainties in the estimates of proved reserves;
- the availability and capacity of gathering and processing systems, pipelines, and other midstream infrastructure for our production;
- 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 strength and financial resources of our competitors;
- our ability to successfully identify, execute, and integrate acquisitions;
- our ability to market our production;
- the effect of environmental liabilities;
- 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 81% and 79% of our revenue during the three and six months ended June 30, 2019, respectively, was from the sale of oil. A $5 per barrel change in our realized oil price would have resulted in a $12.2 million and $27.0 million change in revenues during the three and six months ended June 30, 2019, respectively; a $0.25 per Mcf change in our realized natural gas price would have resulted in a $3.0 million and $5.8 million change in our natural gas revenues for the three and six months ended June 30, 2019, respectively; and a $5 per barrel change in our realized NGL price would have resulted in a $5.6 million and $10.8 million change in our NGL revenues for the three and six months ended June 30, 2019, respectively.

During the three months ended June 30, 2019, the average price of oil was higher than it was in the first quarter of 2019 whereas the average prices for natural gas and NGLs were lower. 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, 2019, we had open oil and natural gas derivatives in a net asset position with a fair value of $12.1 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 $12.1 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 $9.4 million.

Interest Rate Risk - At June 30, 2019, we had $165.0 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, 2019, we incurred interest expense of $2.1 million and $4.3 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%, our interest expense in the three and six months ended June 30, 2019 would have changed by approximately $0.5 million and $1.0 million, respectively.

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

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

We believe that our exposure to counterparty risk decreased slightly during the second quarter of 2019 as the amounts due to us from counterparties decreased.

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, 2019, 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 20, 2019. 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 20, 2019. 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, 2019 - April 30, 2019 (1)	24,609	$ 5.12
May 1, 2019 - May 31, 2019 (1)	22,860	5.23
June 1, 2019 - June 30, 2019 (1)	996	$ 4.71
Total	48,465	

(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
10.1	Form of Performance-Vested Stock Unit Agreement (2019) *
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 - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL 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 31st day of July, 2019.

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)

Performance-Vested Stock Unit Agreement
(2019)

On February 4, 2019, SRC ENERGY INC., a Colorado corporation (the "Company"), pursuant to its 2015 Equity Incentive Plan, as amended from time to time (the "Plan"), granted to the holder listed below ("Participant"), the performance-vested stock units set forth below (individually and collectively referred to as the "Performance-Vested Stock Units" or "PSUs"). As described herein, a portion of the PSUs is earned based on the relative total shareholder return of the Company as compared to certain peer companies ("Relative TSR PSUs") and a portion of the PSUs is earned based on the Company's total shareholder return as compared to predetermined hurdle rates (the "Absolute TSR PSUs"). The grant is subject to and governed by the Plan generally, and all capitalized terms not defined herein shall have the meanings given to such terms in the Plan.

Notice of Performance-Vested Stock Unit Award

Participant	[__________]
Grant Date	February 4, 2019
Target Number of Relative TSR PSUs ("Relative TSR Target PSUs")	[__________]
Target Number of Absolute TSR PSUs ("Absolute TSR Target PSUs")	[__________]
Overview	Relative TSR PSUs Pursuant to the terms and conditions set forth below, Participant may vest in 0% - 200% of the Relative TSR Target PSUs, based on the relative total shareholder return ("TSR," as defined below) of the Company over the Performance Period, measured against the PSU Peer Companies identified below. Absolute TSR PSUs Pursuant to the terms and conditions set forth below, Participant may vest in 0% - 200% of the Absolute TSR Target PSUs based on the Company's TSR over the Performance Period as compared to predetermined Company TSR hurdle rates.

	Employment Required Except as set forth below under "Special Vesting Events," Participant must be employed continuously from the Grant Date through the end of the Performance Period in order to vest in any PSUs hereunder.
Performance Period	January 1, 2019 – December 31, 2021
PSU Peer Companies	"PSU Peer Companies" means the thirteen companies listed below: Callon Petroleum Company Carrizo Oil & Gas Inc. Centennial Resource Development Extraction Oil & Gas Inc. Gulfport Energy Corp. High Point Energy Corp. Jagged Peak Energy LLC Laredo Petroleum, Inc. Matador Resources Company Oasis Petroleum Inc. PDC Energy, Inc. SM Energy Company Whiting Petroleum Corporation Any PSU Peer Company that ceases to be publicly traded on a national securities exchange at any time during the Performance Period, other than Failed Companies (as defined below) or Delisted Companies (as defined below), will be replaced as a PSU Peer Companies for the Performance Period and such replacement company will be treated as though initially included as a PSU Peer Company from the first day of the Performance Period. Replacement PSU Peer Companies shall be selected by the Administrator in its sole discretion from among the following companies: Bonanza Creek Energy, Inc. Berry Petroleum Roan Resources If none of the foregoing companies are available to serve as a replacement PSU Peer Company (because such entities are delisted, acquired, declare bankruptcy, etc.), the Administrator may select any necessary replacement PSU Peer Company in its discretion in a manner designed to preserve (but not enhance) the incentive intended by this Agreement.

	"Failed Companies" shall mean PSU Peer Companies that cease to be publicly traded on a national securities exchange at any time during the Performance Period as a result of a liquidation commenced under Chapter 7 of the Bankruptcy Code, an assignment of the Company's assets for the benefit of creditors under applicable state law, or the commencement of a reorganization proceeding under Chapter 11 of the Bankruptcy Code. "Delisted Companies" shall mean PSU Peer Companies that cease to be publicly traded on a national securities exchange at any time during the Performance Period (irrespective of whether they again become publicly traded on a national securities exchange during the Performance Period) as a result of any involuntary failure to meet the listing requirements of such national securities exchange (such as any failure to meet the minimum common stock price requirement of the exchange), but shall not include any PSU Peer Company that does not meet the listing requirements as a result of any voluntary going private or similar transaction.
Award Determination (Relative TSR PSUs)	Except as set forth below under the headings "Special Vesting Events" and "Change in Control," the number of Relative TSR PSUs earned by the Participant hereunder shall be determined in accordance with this section. At the end of the Performance Period, the PSU Peer Companies and the Company shall be ranked together based on their TSR for the Performance Period with the highest TSR company being number 1 and the lowest TSR being the number of PSU Peer Companies, including the Company, remaining in the group at the end of the Performance Period, with any and all Failed Companies and Delisted Companies being ranked in last place on the list. In addition, of the PSU Peer Companies remaining in the group, the ones ranked first and last shall be disregarded from the overall ranking. Based on the Company's relative TSR rank among the remaining PSU Peer Companies (the "Remaining PSU Peer Companies") for the Performance Period, Participant will vest in PSUs as determined by the Company's rank as follows: • If the Company is ranked among the top three companies of the Remaining PSU Peer Companies (including the Company), Participant shall vest in 200% of the Relative TSR Target PSUs • If the Company's ranking is among four through seven (inclusive) of the Remaining PSU Peer Companies (including the Company), Participant shall vest in 100% of the Relative TSR Target PSUs

• If the Company is ranked eight or lower (inclusive) of the Remaining PSU Peer Companies (including the Company), but not last, Participant shall vest in 50% of the Relative TSR Target PSUs

• If the Company is ranked last of the of the Remaining PSU Peer Companies, no PSUs shall vest and the Participant shall not be entitled to any payment hereunder

Notwithstanding the foregoing, if the Company's overall TSR for the Performance Period is negative, then the number of Relative TSR PSUs vested in accordance with this section shall be equal to 50% of the number of Relative TSR PSUs that would otherwise have vested based on the Company's relative TSR over the Performance Period.

Any fractionally vested PSU will be rounded down to the next whole number.

Award Determination (Absolute TSR PSUs)

Except as set forth below under the headings "Special Vesting Events" and "Change in Control," the number of Absolute TSR PSUs earned by the Participant shall be determined based solely on the Company's TSR over the Performance Period, in accordance with the following table:

Company TSR (Measured over the Performance Period)	% of Absolute TSR Target PSUs Earned
Less than 10.00%	0%
10.00% or more but less than 30.00%	25%
30.00% or more but less than 50.00%	100%
50.00% or greater	200%

If the Company's TSR over the Performance Period falls in between any of the hurdle rates set forth above, the number of Absolute TSR PSUs that vest shall be determined based on linear interpolation.

Special Vesting Events	<u>Termination Without "Cause" or for "Good Reason"</u> In the event of the termination of Participant's continuous employment by the Company without "cause" (as defined in the Plan), or for Good Reason (as defined below), then (A) the Participant's Relative TSR Target PSUs and Absolute TSR PSUs (collectively the "<u>Target PSUs")</u> shall each be reduced and upon termination shall be equal to the product of (i) the Target PSUs, *multiplied by* (ii) a fraction, (x) the numerator of which is the number of days Participant remained in continuous employment from the start of the Performance Period through the date of termination, and (y) the total number of days in the Performance Period, and (B) the Target PSUs shall remain outstanding and the Participant shall be entitled to receive payment (if any) in respect of such reduced Target PSUs at the end of the Performance Period or upon a Change in Control as if Participant's employment had not terminated. "<u>Good Reason</u>" shall mean the occurrence of any of the following without the express written consent of Participant, (i) a material reduction or change in Participant's title or job duties, responsibilities and requirements inconsistent with Participant's position with the Company and Participant's prior duties, responsibilities and requirements, (ii) a material reduction in the Participant's base salary or bonus opportunity unless a proportionate reduction is made to the base salary or bonus opportunity of all members of the Company's senior management in accordance with a bona-fide downturn in the Company's business; (iii) a change of more than 50 miles in the geographic location at which the Participant primarily performs services for the Company; or (iv) any material breach by the Company of any employment or severance agreement between the Company and the Participant. In the case of Participant's allegation of Good Reason, (1) Participant shall provide written notice to the Company of the event alleged to constitute Good Reason within 30 days after the initial occurrence of such event, (2) the Company shall have the opportunity to remedy the alleged Good Reason event within 30 days from receipt of notice of such allegation, and (3) if the event is not timely remedied, the Participant must terminate employment within 30 days after the expiration of the cure period.

	Death or Disability In the event of the termination of Participant's continuous employment with the Company on account of Participant's death or Disability (as defined below), then the Performance Period shall be deemed to have ended as of the Participant's termination of continuous employment, and Participant shall have earned one hundred percent (100%) of the Relative TSR Target PSUs and one hundred percent (100%) of the Absolute TSR Target PSUs. "Disability" shall have the meaning set forth in Treasury Regulation Section 1.409A-3(i)(4).
Change in Control	In the event of a Change in Control (as defined in the Plan), the Performance Period shall end as of the date of the Change in Control, and the Participant will vest in that number of PSUs determined in accordance with the methodology set forth in the "Award Determination (Relative TSR PSUs" and "Award Determination (Absolute TSR PSUs") sections above, based on the Participant's Target PSUs and the Company's absolute and relative TSR as of the date of the Change in Control, as applicable.
Payment	Except as set forth below, the Company shall issue to Participant one share of Common Stock for each PSU that vests hereunder, with the delivery of such Common Stock to occur as soon as reasonably practicable following the certification of results for the Performance Period, but in all events within seventy-four (74) days following the last day of the Performance Period (as same may be truncated upon a Change in Control or termination of employment). Notwithstanding the foregoing, if delivery of shares of Common Stock would, either alone or in combination with other Plan awards, result in the Company exceeding the Plan's Share Limit, then the Company may instead settle some or all of the vested PSUs granted hereunder by paying cash to the Participant on the same date as when shares of Common Stock would have otherwise been issued to the Participant. The amount payable for each cash-settled vested PSU shall be equal to the Fair Market Value on the settlement date of one share of Common Stock. The determination as to whether any vested PSUs shall be settled in cash, and if so, the number thereof, shall be made by the Administrator in its sole and absolute discretion, and neither the Administrator nor the Company shall have any liability to the Participant with respect to any such determination. The Participant hereby acknowledges and agrees that the Administrator need not treat similar Plan awards or award holders the same, and may select in its discretion which Plan awards or portions therefor shall be settled in cash in order to stay within the Share Limit.

Dividend Equivalent Right	Participant shall be entitled in respect of any vested PSUs to receive an additional amount in cash equal to the value of all dividends and distributions made between the Grant Date and the PSU payment date with respect to a number of shares of Common Stock equal to the number of vested PSUs (the "<u>Dividend Equivalent Amounts</u>"). The Dividend Equivalent Amounts shall be accumulated and paid on the date on which the PSUs to which they relate are paid.
TSR and Related Definitions	<u>TSR</u> TSR for the Company or any PSU Peer Company shall mean the percentage equal to (x) the Performance Period Value Change (as defined below) divided by (y) the Beginning Value (as defined below). <u>Beginning Value</u> Beginning Value for the Company or any PSU Peer Company shall mean the Average Share Price for the ten (10) trading days for the period ending on the first day of the Performance Period. <u>Performance Period Value Change</u> Performance Period Value Change for the Company or any PSU Peer Company shall mean the result of: (1) Average Share Price (as defined below) for the last ten (10) trading days of the Performance Period, <u>*minus*</u> (2) Beginning Value, <u>*plus*</u> (3) Dividends (cash or stock based on ex-dividend date) paid per share of company common stock over the Performance Period. In the case of Change in Control, the actual share price used for consummation of the transaction shall be used in place of the Average Share Price (as defined below) for the last ten (10) trading days of the Performance Period. <u>Average Share Price</u> Average Share Price for the Company or any PSU Peer Company shall mean the average daily closing price of the applicable company's common stock over the relevant period on the principal securities exchange on which such shares are traded, as published by a reputable source.
Other Terms and Conditions	Are set forth in the accompanying Performance Vested Stock Unit Grant Terms and Conditions and the Plan.

By executing this letter below, Participant and the Company agree that the Performance-Vested Stock Units granted hereby are granted under and governed by the terms and conditions of the Plan and this Performance-Vested Stock Unit Agreement (including this Notice of Performance-Vested Stock Unit Award and the accompanying Performance-Vested Stock Unit Terms and Conditions) (the "Grant Documents"). Participant hereby represents and acknowledges that he or she has been provided the opportunity to review the Plan and the Grant Documents in their entirety, and Participant hereby agrees to accept as binding, conclusive, and final all decisions or interpretations of the Administrator upon any questions relating to the Plan and the Grant Documents.

IN WITNESS WHEREOF, the parties have executed this Performance-Vested Stock Unit Agreement, effective as of the Grant Date.

SRC ENERGY INC.	**GRANTEE**
______________________________	______________________________
Lynn A Peterson Chief Executive Officer and President Date	Name

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.

July 31, 2019

/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.

July 31, 2019

/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, 2019 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:	July 31, 2019	By:	/s/ Lynn A. Peterson
			Lynn A. Peterson, Principal Executive Officer
Date:	July 31, 2019	By:	/s/ James P. Henderson
			James P. Henderson, Principal Financial Officer