UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the Quarterly Period Ended March 31, 2020

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 001-38606

Berry Corporation (bry)
(Exact name of registrant as specified in its charter)

Delaware	**81-5410470**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

16000 Dallas Parkway, Suite 500
Dallas, Texas 75248
(661) 616-3900
(Address of principal executive offices, including zip code
Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, par value $0.001 per share	BRY	Nasdaq Global Select Market

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405) 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 emerging growth company. See 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 ☒

Shares of common stock outstanding as of April 30, 2020 79,758,415

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The financial information and certain other information presented in this report have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables in this report. In addition, certain percentages presented in this report reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, or may not sum due to rounding.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

BERRY CORPORATION (bry)
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2020	December 31, 2019
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ —
Accounts receivable, net of allowance for doubtful accounts of $2,303 at March 31, 2020 and $1,103 at December 31, 2019	48,602	71,867
Derivative instruments	169,859	9,166
Other current assets	19,730	19,399
Total current assets	238,192	100,432
Noncurrent assets:		
Oil and natural gas properties	1,357,496	1,675,717
Accumulated depletion and amortization	(146,158)	(209,105)
Total oil and natural gas properties, net	1,211,338	1,466,612
Other property and equipment	109,094	135,117
Accumulated depreciation	(24,819)	(25,462)
Total other property and equipment, net	84,275	109,655
Derivative instruments	15,245	525
Other noncurrent assets	10,480	12,974
Total assets	$ 1,559,530	$ 1,690,198
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 108,720	$ 151,811
Derivative instruments	—	4,817
Total current liabilities	108,720	156,628
Noncurrent liabilities:		
Long-term debt	403,663	394,319
Derivative instruments	283	141
Deferred income taxes	35,404	9,057
Asset retirement obligation	134,877	124,019
Other noncurrent liabilities	26,757	33,586
Commitments and Contingencies - Note 4		
Equity:		
Common stock ($.001 par value; 750,000,000 shares authorized; 84,863,263 and 84,655,222 shares issued; and 79,751,017 and 79,542,976 shares outstanding, at March 31, 2020 and December 31, 2019, respectively)	85	85
Additional paid-in-capital	904,072	901,830
Treasury stock, at cost, (5,112,246 shares at March 31, 2020 and at December 31, 2019)	(49,995)	(49,995)
Retained earnings (deficit)	(4,336)	120,528
Total equity	849,826	972,448
Total liabilities and equity	$ 1,559,530	$ 1,690,198

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

BERRY CORPORATION (bry)
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31,	
	2020	**2019**
	(in thousands, except per share amounts)	
Revenues and other:		
Oil, natural gas and natural gas liquids sales	$ 122,098	$ 131,102
Electricity sales	5,461	9,729
Gains (losses) on oil derivatives	211,229	(65,239)
Marketing revenues	453	830
Other revenues	24	117
Total revenues and other	339,265	76,539
Expenses and other:		
Lease operating expenses	50,752	57,928
Electricity generation expenses	3,946	7,760
Transportation expenses	1,822	2,173
Marketing expenses	430	851
General and administrative expenses	19,337	14,340
Depreciation, depletion, and amortization	35,329	24,585
Impairment of oil and gas properties	289,085	—
Taxes, other than income taxes	4,352	8,086
Losses (gains) on natural gas derivatives	12,035	(2,115)
Other operating expenses	2,202	1,245
Total expenses and other	419,290	114,853
Other (expenses) income:		
Interest expense	(8,920)	(8,805)
Other, net	(6)	154
Total other (expenses) income	(8,926)	(8,651)
Reorganization items, net	—	(231)
Loss before income taxes	(88,951)	(47,196)
Income tax expense (benefit)	26,349	(13,098)
Net loss	$ (115,300)	$ (34,098)
Net loss per share:		
Basic	$ (1.45)	$ (0.42)
Diluted	$ (1.45)	$ (0.42)

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

BERRY CORPORATION (bry)
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	Three-Month Period Ended March 31, 2019				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Equity
	(in thousands)				
December 31, 2018	$ 82	$ 914,540	$ (24,218)	$ 116,042	$ 1,006,446
Shares withheld for payment of taxes on equity awards and other	—	(270)	—	—	(270)
Stock based compensation	—	1,498	—	—	1,498
Purchases of treasury stock	—	—	(24,375)	—	(24,375)
Purchase of rights to common stock[(1)]	—	(20,265)	20,265	—	—
Common stock issued to settle unsecured claims	3	(3)	—	—	—
Dividends declared on common stock, $0.12/share	—	—	—	(10,072)	(10,072)
Net loss	—	—	—	(34,098)	(34,098)
March 31, 2019	$ 85	$ 895,500	$ (28,328)	$ 71,872	$ 939,129

	Three-Month Period Ended March 31, 2020				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Deficit)	Total Equity
	(in thousands)				
December 31, 2019	$ 85	$ 901,830	$ (49,995)	$ 120,528	$ 972,448
Shares withheld for payment of taxes on equity awards and other	—	(794)	—	—	(794)
Stock based compensation	—	3,036	—	—	3,036
Dividends declared on common stock, $0.12/share	—	—	—	(9,564)	(9,564)
Net loss	—	—	—	(115,300)	(115,300)
March 31, 2020	$ 85	$ 904,072	$ (49,995)	$ (4,336)	$ 849,826

(1) In 2018, we entered into several settlement agreements with general unsecured creditors from our bankruptcy process. We paid approximately $20 million to purchase their claims to our common stock. These claims were settled in February 2019 with no shares issued.

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

BERRY CORPORATION (bry)
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
	2020	**2019**
	(in thousands)	
Cash flows from operating activities:		
Net loss	$ (115,300)	$ (34,098)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	35,329	24,585
Amortization of debt issuance costs	1,338	1,255
Impairment of oil and gas properties	289,085	—
Stock-based compensation expense	2,922	1,474
Deferred income taxes	26,347	(13,098)
Increase in allowance for doubtful accounts	1,200	427
Other operating expenses	1,575	1,245
Derivative activities:		
Total (gains) losses	(199,194)	63,124
Cash settlements on derivatives	19,625	14,904
Changes in assets and liabilities:		
Decrease (increase) in accounts receivable	22,074	(6,084)
Increase in other assets	(331)	(717)
Decrease in accounts payable and accrued expenses	(29,179)	(29,854)
Decrease in other liabilities	(11,008)	(2,066)
Net cash provided by operating activities	44,483	21,097
Cash flows from investing activities:		
Capital expenditures:		
Development of oil and natural gas properties	(45,542)	(47,679)
Purchases of other property and equipment	(1,227)	(1,419)
Changes in capital investment accruals	3,533	(3,693)
Other	198	—
Net cash used in investing activities	(43,038)	(52,791)
Cash flows from financing activities:		
Borrowings under RBL credit facility	124,100	15,350
Repayments on RBL credit facility	(115,000)	(15,350)
Dividends paid on common stock	(9,750)	(9,813)
Purchase of treasury stock	—	(25,241)
Shares withheld for payment of taxes on equity awards and other	(794)	(270)
Net cash used in financing activities	(1,444)	(35,324)
Net increase (decrease) in cash and cash equivalents	1	(67,018)
Cash and cash equivalents:		
Beginning	—	68,680
Ending	$ 1	$ 1,662

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

Note 1 - Basis of Presentation

Effective February 18, 2020, Berry Petroleum Corporation changed its name to Berry Corporation (bry) and introduced a new logo. We believe that the name Berry Corporation (bry) is a name that better represents our progressive approach to evolving and growing the business in today's dynamic oil and gas industry.

"Berry Corp." refers to Berry Corporation (bry), a Delaware corporation, which is the sole member of Berry Petroleum Company, LLC ("Berry LLC").

As the context may require, the "Company", "we", "our" or similar words refer to (i) Berry Corp. and Berry LLC, its consolidated subsidiary, as a whole or (ii) either Berry Corp. or Berry LLC.

Nature of Business

Berry Corp. is an independent oil and natural gas company that was incorporated under Delaware law on February 13, 2017. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located in the United States (the "U.S."), in California (in the San Joaquin and Ventura basins), Utah (in the Uinta basin), and Colorado (in the Piceance basin).

Principles of Consolidation and Reporting

The condensed consolidated financial statements were prepared in conformity with U.S. generally accepted accounting principles ("GAAP"), which requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. In management's opinion, the accompanying financial statements contain all normal, recurring adjustments that are necessary to fairly present our interim unaudited condensed consolidated financial statements. We eliminated all significant intercompany transactions and balances upon consolidation. For oil and gas exploration and production joint ventures in which we have a direct working interest, we account for our proportionate share of assets, liabilities, revenue, expense and cash flows within the relevant lines of the financial statements.

We prepared this report pursuant to the rules and regulations of the U.S. Security and Exchange Commission ("SEC") applicable to interim financial information, which permit the omission of certain disclosures to the extent they have not changed materially since the latest annual financial statements. We believe our disclosures are adequate to make the disclosed information not misleading. The results reported in these unaudited condensed consolidated financial statements may not accurately forecast results for future periods. This Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and the notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2019.

Reclassification

We reclassified certain prior year amounts in the cash flow statements to conform to the current year presentation. These reclassifications had no material impact on the financial statements.

New Accounting Standards Issued, But Not Yet Adopted

In February 2016, the FASB issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 15, 2020, including interim periods within those fiscal years. The FASB has issued a proposal to further delay implementation, which has not been finalized yet. We are currently identifying our lease population in accordance with the new lease standard. We expect the adoption of these rules to increase other assets and other liabilities on our balance sheet and we are currently evaluating the impact on our consolidated results of operations.

In December 2019, the FASB issued rules which simplify the accounting for income taxes. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers which is for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. We are currently evaluating the impact of these rules on our consolidated financial statements.

In March 2020, the FASB issued rules providing optional expedients and exceptions for applying GAAP to contracts, hedging relationships and other transactions affected by the reference rate reform, if certain criteria are met. The optional expedient for contract modifications applies to contract modifications that replace a reference rate affected by the reference rate reform, such as the London Interbank Offered Rate ("LIBOR"). Entities may elect to apply the amendments for contract modifications as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020 through December 31, 2022. We are currently evaluating the impact of these rules on our consolidated financial statements.

Note 2 - Debt

The following table summarizes our outstanding debt:

	March 31, 2020	December 31, 2019	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ 10,950	$ 1,850	variable rates 4.0% (2020) and 5.5% (2019), respectively	July 29, 2022	Mortgage on 85% of Present Value of proven oil and gas reserves and lien on other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	410,950	401,850			
Less: Debt Issuance Costs	(7,287)	(7,531)			
Long-Term Debt, net	$ 403,663	$ 394,319			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At March 31, 2020 and December 31, 2019, debt issuance costs for the RBL Facility (as defined below) reported in "other noncurrent assets" on the balance sheet were approximately $10 million and $11 million net of amortization, respectively. At March 31, 2020 and December 31, 2019, debt issuance costs, net of amortization, for the unsecured notes due February 2026 (the "2026 Notes") reported in Long-Term Debt, net were approximately $7 million and $8 million, respectively.

For the three months ended March 31, 2020 and March 31, 2019, the amortization expense for the RBL Facility and 2026 Notes were both approximately $1 million and was included in "interest expense" in the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amount of the RBL Facility approximates fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 Notes was approximately $164 million and $376 million at March 31, 2020 and December 31, 2019, respectively.

The RBL Facility

On July 31, 2017, we entered into a credit agreement (“RBL Facility”). The RBL Facility provides for a revolving loan with up to $1.5 billion of commitments, subject to a reserve borrowing base. In late 2019, we completed a borrowing base redetermination under our RBL Facility that set our borrowing base to $500 million and reaffirmed our elected commitment amount at $400 million. The RBL Facility matures on July 29, 2022, unless terminated earlier in accordance with the RBL Facility terms. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. While we have submitted our most recent borrowing base redetermination, we have not yet received the results.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral.

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.0 to 1.0 and (ii) a Current Ratio of at least 1.0 to 1.0. The RBL Facility also contains customary restrictions. As of March 31, 2020, our Leverage Ratio and Current Ratio were 1.4 to 1.0 and 4.2 to 1.0, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the RBL Facility as of March 31, 2020.

As of March 31, 2020, we had approximately $11 million in borrowings outstanding, $7 million in letters of credit outstanding, and approximately $382 million of available borrowings capacity under the RBL Facility.

Bond Repurchase Program

In February 2020, our Board of Directors adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase the 2026 Notes during any period or at all.

Corporate Organization

Berry Corp., as Berry LLC’s parent company, has no independent assets or operations. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. Berry Corp. and Berry LLC currently do not have any other subsidiaries. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than under the RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

The RBL Facility permits Berry LLC to make distributions to Berry Corp. so long as both before and after giving pro forma effect to such distribution no default or borrowing base deficiency exists, availability equals or exceeds 15% of the then effective borrowing base, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.75 to 1.00. The conditions are currently met with significant margin.

Note 3 - Derivatives

We utilize derivatives, such as swaps, puts and calls, to hedge a portion of our forecasted oil production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices, which addresses our market risk. We target covering our operating expenses and a majority of our fixed charges, including capital for sustained production levels, interest and dividends, with the oil hedges for a period of up to two years out. Additionally, we target fixing the price for a large portion of our natural gas purchases used in our steam operations for up to two years. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations, which we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions.

For fixed-price oil swaps, we make settlement payments for prices above the indicated weighted-average price per barrel of Brent or WTI and receive settlement payments for prices below the indicated weighted-average price per barrel of Brent or WTI.

For our purchased oil calls, we would receive settlement payments for prices above the indicated weighted-average price per barrel of Brent.

For fixed-price gas purchase swaps, we are the buyer so we make settlement payments for prices below the weighted-average price per MMBtu and receive settlement payments for prices above the weighted-average price per MMBtu.

We use oil swaps and puts to protect against decreases in the oil price and natural gas swaps to protect against increases in natural gas prices. We do not enter into derivative contracts for speculative trading purposes and have not accounted for our derivatives as cash-flow or fair-value hedges. The changes in fair value of these instruments are recorded in current earnings. (Gains) losses on oil hedges are classified in the revenues and other section of the statement.

As of March 31, 2020, we had the following crude oil production and gas purchases hedges.

	Q2 2020	Q3 2020	Q4 2020	FY 2021
Fixed Price Oil Swaps (Brent):				
Hedged volume (MBbls)	2,184	2,208	2,208	3,282
Weighted-average price ($/Bbl)	$ 59.91	$ 59.85	$ 59.85	$ 47.19
Fixed Price Oil Swaps (WTI):				
Hedged volume (MBbls)	30	—	—	—
Weighted-average price ($/Bbl)	$ 61.75	$ —	$ —	$ —
Purchased Oil Calls Options (Brent):				
Hedged volume (MBbls)	273	276	276	—
Weighted-average price ($/Bbl)	$ 65.00	$ 65.00	$ 65.00	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	5,005,000	5,060,000	3,840,000	8,500,000
Weighted-average price ($/MMBtu)	$ 2.89	$ 2.89	$ 2.73	$ 2.62
Fixed Price Gas Purchase Swaps (SoCal Citygate):				
Hedged volume (MMBtu)	455,000	460,000	155,000	—
Weighted-average price ($/MMBtu)	$ 3.80	$ 3.80	$ 3.80	$ —

In April 2020 we added fixed price gas purchase swaps (Kern, Delivered) of 10,000 MMbtu/d at $2.79 beginning November 2020 through October 2021.

Our commodity derivatives are measured at fair value using industry-standard models with various inputs including publicly available underlying commodity prices and forward curves, and all are classified as Level 2 in the required fair value hierarchy for the periods presented. These commodity derivatives are subject to counterparty netting. The following tables present the fair values (gross and net) of our outstanding derivatives as of March 31, 2020 and December 31, 2019:

	March 31, 2020			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented on the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 181,696	$ (11,837)	$ 169,859
Commodity Contracts	Non-current assets	16,033	(788)	15,245
Liabilities:				
Commodity Contracts	Current liabilities	(11,837)	11,837	—
Commodity Contracts	Non-current liabilities	(1,071)	788	(283)
Total derivatives		$ 184,821	$ —	$ 184,821

	December 31, 2019			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented on the Balance Sheet
	(in thousands)			
Assets:				
Commodity Contracts	Current assets	$ 17,799	$ (8,633)	$ 9,166
Commodity Contracts	Non-current assets	773	(248)	525
Liabilities:				
Commodity Contracts	Current liabilities	(13,450)	8,633	(4,817)
Commodity Contracts	Non-current liabilities	(389)	248	(141)
Total derivatives		$ 4,733	$ —	$ 4,733

By using derivative instruments to economically hedge exposure to changes in commodity prices, we expose ourselves to credit risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. We do not receive collateral from our counterparties.

We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, our RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A- or A3 credit rating or better from Standards & Poor's or Moody's, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which partially mitigates the counterparty nonperformance risk.

Note 4 - Lawsuits, Claims, Commitments and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at March 31, 2020 and December 31, 2019. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of March 31, 2020, we are not aware of material indemnity claims pending or threatened against us.

We have certain commitments under contracts, including purchase commitments for goods and services. We previously had an obligation to a counterparty in connection with our Piceance assets to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. The counterparty has since filed a claim challenging the sufficiency of such access which we dispute. We intend to defend the matter vigorously, however, given the uncertainty of litigation and the preliminary stage of the case, among other things, at this time we cannot estimate the reasonable possible loss, if any, that may result from this action.

Note 5 - Equity

Cash Dividends

Our board of directors approved a $0.12 per share quarterly cash dividend on our common stock for the first quarter of 2020, which we paid in April 2020. However, in April 2020, in connection with the current low oil price environment, we temporarily suspended our quarterly dividend until oil prices recover.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board’s evaluation of market conditions for our common stock at that time, they authorized initial repurchases of up to $50 million under the program. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. We are not required or otherwise obligated to repurchase any additional shares any repurchases may be commenced or suspended at any time without notice. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes. The Company had repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million as of December 31, 2019. For the three months ended March 31, 2020, we did not repurchase any shares under the stock repurchase program.

Stock-Based Compensation

In March 2020, the Company granted awards of 1,817,656 shares of restricted stock units (“RSUs”), which will vest annually in equal amounts over three years and 1,278,877 performance-based restricted stock units (“PSUs”), which will cliff vest at three years. The fair value of these awards was approximately $32 million.

The RSUs awarded are service-based awards. The PSUs awarded include a market objective measured against both absolute total stockholder return (“Absolute TSR”) and total stockholder return relative (“Relative TSR”) to the Vanguard World Fund - Vanguard Energy ETF index (the “Index”) over the performance period, assuming the reinvestment of dividends. Depending on the results achieved during the three-year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 200% of the Target Shares granted.

The fair value of the PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the Index over the performance periods. The expected volatility of the Company's common stock at the date of grant was estimated based on blended historical average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the current annualized declared dividend. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate three-year performance measurement period.

Note 6 - Supplemental Disclosures to the Financial Statements

Other current assets reported on the condensed consolidated balance sheets included the following:

	March 31, 2020	December 31, 2019
	(in thousands)	
Prepaid expenses	$ 4,768	$ 4,577
Materials and supplies	10,972	10,544
Oil inventories	3,144	3,432
Other	846	846
Total other current assets	$ 19,730	$ 19,399

Other non-current assets at March 31, 2020 and December 31, 2019, included approximately $10 million and $11 million of deferred financing costs, net of amortization, respectively.

Accounts payable and accrued expenses on the condensed consolidated balance sheets included the following:

	March 31, 2020	December 31, 2019
	(in thousands)	
Accounts payable-trade	$ 10,796	$ 13,986
Accrued expenses	48,877	57,078
Royalties payable	9,897	25,385
Taxes other than income tax liability	11,656	9,150
Accrued interest	3,500	10,500
Dividends payable	9,703	9,888
Asset retirement obligation - current portion	13,700	25,208
Other	591	616
Total accounts payable and accrued expenses	$ 108,720	$ 151,811

We reclassified certain accrued expenses to accounts payable trade accounts for the prior period to conform to the current year presentation. These reclassifications had no impact on the financial statements.

The increase in the long-term portion of the asset retirement obligation from $124 million at December 31, 2019 to $135 million at March 31, 2020 was due to $2 million of accretion and reclassification of $12 million from the current portion due to changes in budgeted spending and minimum state requirements. These increases were partially offset by $3 million of liabilities settled during the period.

Other non-current liabilities at March 31, 2020 and December 31, 2019 included approximately $27 million and $33 million of greenhouse gas liability, respectively.

Supplemental Information on the Statement of Operations

Other operating expenses were $2.2 million and $1.2 million for the three months ended March 31, 2020 and March 31, 2019. These expenses mainly consist of excess abandonment costs and drilling rig standby charges in 2020 and excess abandonment costs in 2019.

Supplemental Cash Flow Information

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Three Months Ended March 31,	
	2020	2019
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 696	$ 1,986
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 14,879	$ 14,000
Income taxes	$ 2	$ —

Cash and cash equivalents consist primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value. As part of our cash management system, we use a controlled disbursement account to fund cash distribution checks presented for payment by the holder. Checks issued but not yet presented to banks may result in overdraft balances, which amounts are immaterial for these periods, for accounting purposes in the accounts payable and accrued expenses account.

Note 7 - Earnings Per Share

We calculate basic earnings (loss) per share by dividing net income (loss) by the weighted-average number of common shares outstanding during the three months ended March 31, 2020 and 2019 which is approximately 80 million shares and 82 million shares, respectively. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, are considered common shares outstanding and are included in the computation of net income (loss) per share.

The RSUs and PSUs are not a participating security as the dividends are forfeitable. For the three months ended March 31, 2020 and March 31, 2019, no incremental RSUs or PSUs were included in the diluted EPS calculation as their effect was anti-dilutive under the “if converted” method.

	Three Months Ended March 31,	
	2020	2019
	(in thousands except per share amounts)	
Basic EPS calculation		
Net loss	$ (115,300)	$ (34,098)
Weighted-average shares of common stock outstanding	79,608	81,765
Basic loss per share	$ (1.45)	$ (0.42)
Diluted EPS calculation		
Net loss	$ (115,300)	$ (34,098)
Weighted-average shares of common stock outstanding	79,608	81,765
Dilutive effect of potentially dilutive securities(1)	—	—
Weighted-average common shares outstanding - diluted	79,608	81,765
Diluted loss per share	$ (1.45)	$ (0.42)

(1) No potentially dilutive securities were included in computing earnings (loss) per share for the three months ended March 31, 2020 and March 31, 2019, because the effect of inclusion would have been anti-dilutive.

Note 8 - Revenue Recognition

We account for revenue in accordance with the Accounting Standards Codification 606, Revenue from Contracts with Customers, which we adopted on January 1, 2019, using the modified retrospective method, which was applied to all contracts that were not completed as of that date. Prior period results were not adjusted and continue to be reported under the accounting standards in effect for the prior period. The new standard did not affect the timing of our revenue recognition and did not impact net income; accordingly, we did not record an adjustment to the opening balance of retained earnings.

We adopted the practical expedient related to disclosing the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied at the end of the reporting period. The performance obligations that are unsatisfied at the end of a reporting period relate solely to future volumes that we have yet to sell. As such, these are wholly unsatisfied performance obligations as each unit of product represents a separate performance obligation as well as a wholly unsatisfied promise to transfer a distinct good that forms part of a single performance obligation.

We derive substantially all of our revenue from sales of oil, natural gas and natural gas liquids (“NGL”), with the remaining revenue generated from sales of electricity and marketing activities.

The following is a description of our principal activities from which we generate revenue. Revenues are recognized when a customer obtains control of promised goods or services, in an amount that reflects the consideration we expect to receive in exchange for those goods or services.

Oil, Natural Gas and NGLs

We recognize revenue from the sale of our oil, natural gas and NGLs production when delivery has occurred and control passes to the customer. Our oil and natural gas contracts are short term, typically less than a year and our NGL contracts are both short and long term. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Our commodity sales contracts are indexed to a market price or an average index price. We recognize revenue in the amount that we expect to receive once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following invoicing.

Electricity Sales

The electrical output of our cogeneration facilities that is not used in our operations is sold to the California market based on market pricing, which includes capacity payments. The majority of the portion sold from three of our cogeneration facilities is sold under long-term contracts to two California utility companies, based on market pricing. Revenue is recognized over time when obligations under the terms of a contract with our customer are satisfied; generally, this occurs upon delivery of the electricity. Revenue is measured as the amount of consideration we expect to receive based on average index pricing with payment due the month following delivery. Capacity payments are based on a fixed annual amount per kilowatt hour and monthly rates vary based on seasonality, which is consistent with how we earn the capacity payment. Capacity payments are settled monthly. We consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments. We report electricity revenue as electricity sales on our consolidated statements of operations.

Marketing Revenue

Marketing revenue primarily includes our activities associated with transporting and marketing third-party volumes. These sales are made under the same agreements with the same purchaser as our natural gas sales discussed above. We consider our performance obligations to be satisfied upon transfer of control of the commodity. Revenues are presented excluding costs incurred prior to transferring control of these volumes to the customer, or the costs to purchase these volumes when we are acting as the principal. The revenues and expenses related to the sale and purchase of third-party volumes are presented separately as marketing revenue and marketing expenses on the condensed consolidated statements of operations.

Disaggregated Revenue

As a result of adoption of this standard, we are now required to disclose the following information regarding revenue from contracts with customers on a disaggregated basis.

	Three Months Ended March 31,	
	2020	2019
	(in thousands)	
Oil sales	$ 118,310	$ 123,450
Natural gas sales	3,368	6,715
Natural gas liquids sales	420	937
Electricity sales	5,461	9,729
Marketing revenues	453	830
Other revenues	24	117
Revenues from contracts with customers	128,036	141,778
Gains (losses) on oil derivatives	211,229	(65,239)
Total revenues and other	$ 339,265	$ 76,539

Note 9—Oil and Natural Gas Properties

We evaluate the impairment of our proved and unproved oil and natural gas properties whenever events or changes in circumstance indicate that a property's carrying value may not be recoverable. If the carrying amount of the proved properties exceeds the estimated undiscounted future cash flows, we record an impairment charge to reduce the carrying values of proved properties to their estimated fair value. We estimate the fair values of proved properties using valuation techniques that consider the market approach for values from the recent sale of similar properties, if applicable, and the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a risk-adjusted discount rate. These inputs require significant judgments and estimates by our management at the time of the valuation which can change significantly over time. The underlying commodity prices are embedded in our estimated cash flows and are the product of a process that begins with the relevant forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors our management believes will impact realizable prices. The fair value was estimated using inputs characteristic of a Level 3 fair value measurement.

We evaluate the impairment of our unproved oil and gas properties whenever events or changes in circumstances indicate the carrying value may not be recoverable. If exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of such properties would be expensed. The timing of any write-downs of unproved properties, if warranted, depends upon management’s plans, the nature, timing and extent of future exploration and development activities and their results.

At March 31, 2020, we performed impairment tests with respect to our proved and unproved oil and gas properties as a result of significant declines in oil prices during the latter part of the first quarter. These declines were driven by the uncertainty surrounding the outbreak of novel strain of coronavirus (SARS-Cov-2), which causes COVID-19 (“COVID-19”) and other macroeconomic events such as the geopolitical tensions between OPEC and Russia. The COVID-19 pandemic and related economic repercussions, coupled with OPEC+ actions, created significant volatility, uncertainty, and turmoil in the oil and gas industry, which have negatively affected and are expected to continue to negatively affect our business. Low oil prices are expected to continue for some period as reflected by current futures forward curves for crude.

Consequently, we recorded a non-cash pre-tax asset impairment charge of $289 million on properties in Utah and certain California locations. We evaluate our proved properties in accordance with accounting guidance and fair value techniques utilizing the period-end forward price curve, as well as assessing projects we determine we would not pursue in the foreseeable future given the current environment. We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance at March 31, 2020.

Note 10—Income Taxes

The COVID-19 pandemic and related economic repercussions, coupled with OPEC+ actions, created significant volatility, uncertainty, and turmoil in the oil and gas industry, which have negatively affected and are expected to continue to negatively affect our business. As a result, after evaluating the positive and negative evidence, we determined that it was more likely than not that a large portion of our interest deduction carryforwards and tax credits would not be realized. Accordingly, we recognized a valuation allowance on our deferred tax assets during the quarter in the amount of $51 million. This was the key contributor in the decrease in our effective tax rate from 28% for the three months ended March 31, 2019 to (30)% for the three months ended March 31, 2020.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our interim unaudited consolidated financial statements and related notes presented in this Quarterly Report on Form 10-Q, as well as our audited consolidated financial statements and related notes thereto contained in our Annual Report on Form 10-K for the year ended December 31, 2019 (the "*Annual Report*"*) filed with the Securities and Exchange Commission ("SEC"). When we use the terms "we," "us," "our," the "Company" or similar words in this report, we are referring to Berry Corporation (bry) (formerly known as Berry Petroleum Corporation, and referred to herein as* "*Berry Corp.*"*) and its wholly owned subsidiary, Berry Petroleum, LLC (*"*Berry LLC*"*).*

Our Company

We are a western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived, oil reserves in conventional reservoirs.

In the aggregate, our assets are characterized by high oil content. Most of our assets are located in the oil-rich reservoirs in the San Joaquin basin of California, which has more than 150 years of production history and substantial remaining oil in place. As a result of the substantial data produced over the basin's long history, its reservoir characteristics are well understood, leading to predictable, repeatable, low geological risk and low-cost development opportunities. In California, we focus on conventional, shallow oil reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. We also have assets in the low-cost, oil-rich reservoirs in the Uinta basin of Utah and low geologic risk natural gas resource plays in the Piceance basin in Colorado. We believe that successful execution of our strategy across our low-declining production base and extensive inventory of identified drilling locations should result in our ability, in appropriate oil price environments, to return capital to our stockholders and demonstrate long-term, capital efficient, consistent, and predictable production growth while living within "Levered Free Cash Flow" (a non-GAAP financial measure discussed under "How We Plan and Evaluate Our Operations" in this report).

Effective February 18, 2020, Berry Petroleum Corporation changed its name to "Berry Corporation (bry)" and introduced a new logo, to illustrate our progressive approach to evolving and growing the business in today's dynamic oil and gas industry. Our strategy includes proactively engaging the many forces driving our industry to maximize our assets, create value for shareholders, and support environmental goals that align with a more positive future. One of the more visible elements of our brand is our publicly traded stock, and our new logo echoes the public value of the company by using our ticker symbol as an identifiable element of our brand.

Business Environment, Market Conditions and Outlook

In December 2019, a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19, was reported to have surfaced in China. The spread of this virus has caused increasing disruption globally since January 2020. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic, and the U.S. economy began to experience pronounced effects. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains and created significant volatility and disruption of the financial and commodity markets. In particular, the oil and gas industry continues to be significantly impacted by the rapid, substantial and prolonged deterioration in the price of oil caused by the significant decrease in oil demand because of the COVID-19 pandemic and corresponding preventative measures taken around the world to mitigate the spread of the virus, compounded by a supply surge from Saudi Arabia and Russia.

In the midst of the ongoing COVID-19 pandemic, the Organization of Petroleum Exporting Countries and other oil producing nations ("OPEC+") failed to reach an agreement on production levels for crude oil, at which point Saudi Arabia and Russia aggressively increased oil production and exports. The convergence of these events - the unprecedented dual impact of a severe global oil demand decline due to the COVID-19 pandemic repercussions coupled with a substantial increase in supply from Saudi Arabia and Russia - drove oil prices to extremely low levels and created significant volatility, uncertainty, and turmoil in the oil and gas industry. While in April 2020, OPEC+ agreed to cut production, the production cuts have yet to offset the significant decrease in demand resulting from the COVID-19 pandemic. As a result, the price of oil has remained extremely depressed and even reached historic lows. Additionally, the effects of demand destruction with a supply surge globally have been amplified as available storage for crude oil and refined products is increasingly limited and may be completely unavailable in the near future. With the storage and transportation constraints further adding to the pressure on commodities prices, refiners have started to curtail output and producers all over the world - including in the United States - have started to shut-in production.

Although our financial and operating results for the first quarter of 2020 were not significantly impacted by the convergence of these events, our business, like other oil has producers, has been and is expected to continue to be negatively affected by the global crisis described above. The broad economic repercussions and the impact on the oil and gas industry is anticipated currently to adversely affect our business well into 2021. We are unable to reasonably predict when, or to what extent, commodity prices and the overall markets and global economy will stabilize, and the pace of any subsequent recovery for the oil and gas industry. Further, to what extent these events do ultimately impact our business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors that are not within our control and cannot be predicted, including the duration of the pandemic and speculation as to future actions by Saudi Arabia, Russia and other members of OPEC+. We have taken steps and continue to actively work to mitigate the evolving challenges and mounting repercussions from both the COVID-19 pandemic and the industry downturn on our operations, our financial condition and our people, however, given the tremendous uncertainty and turmoil, there is no certainty that the measures we take will be ultimately sufficient.

As we focus on managing our business and operations in response to this crisis, the safety and well-being of our employees and the communities in which we operate is our top priority. For the protection of our employees and to help contain the spread of COVID-19, we modified our business practices, including temporary closing of offices not required to maintain critical operations and instead allowing a large portion of our workforce to work from home, and we adopted recommended practices with respect to social distancing, quarantines and travel bans and restrictions. Although we managed the transition to remote work arrangements without a loss in business continuity, we incurred additional costs and experienced some inefficiencies; importantly, none of which had an impact on financial reporting systems, internal control over financial reporting or disclosure controls and procedures. We have not had layoffs or furloughs year to date, in part due to the “essential” nature of our business. We remain committed to being a good corporate citizen by focusing on the well-being of our employees and communities, including maintaining our strong environmental standards and investing in community impact initiatives.

As a result of the industry downturn, commodity price outlook, and increasing uncertainty, on April 1, 2020, we provided updated guidance for the 2020 fiscal year, reflecting a heightened focus on preserving cash and reducing costs, including through reducing planned 2020 capital expenditures and non-employee general and administrative expenses and improving operational efficiencies. We also temporarily suspended our quarterly cash dividend, starting with the second quarter of 2020, and year-to-date we have not repurchased any common stock under our authorized share repurchase program. We enhanced our hedge positions for 2020, and to a lesser extent for 2021. Low oil prices are expected to continue for some period as reflected by the current futures forward curve for Brent crude and we are focused on increasing our hedge positions for 2021 to protect against the anticipated prolonged weakness in commodity prices. If we are unable to successfully do so, our financial results for that time may be adversely impacted.

We are actively working to obtain sufficient storage capacity to support our planned production; however, there is significant near-term risk that storage for oil may be insufficient for producers in our areas of operation to continue full production rates in the second quarter of 2020 and potentially beyond. If we are unable to obtain sufficient storage capacity, or if existing capacity become unavailable to us, in either instance on commercially reasonable terms or at all, we could be forced to shut-in some or all of our production or delay or temporarily discontinue our drilling plans. Based on our current storage commitments, and assuming we are unable to obtain sufficient additional storage in the near term, we could be forced to shut-in a significant amount of our California production, as well as curtail some of our Utah and Colorado production, beginning in the second quarter of 2020, which could have a material, adverse effect on our financial condition, liquidity and results of operations. Whether and when we will have to reduce or shut-in production, and the extent and duration to which we may have to do so, cannot be reasonably predicted at this time. The significance of the impact of any production disruptions, including the extent of the adverse impact on our short- and long-term financial condition, liquidity and results of operations, will be dictated by the extent and duration of such disruption, which is unknowable and will, in turn, depend on the how long storage remains filled and unavailable to us, which is also unknowable. Among other consequences, should we significantly curtail or shut-in production, our expectations regarding our 2020 production, capital spend and capital development program will be affected and our previously issued guidance would not likely be achieved. For a discussion of certain potential risks, costs and other considerations related to shutting-in production, please see Part II, Item 1A. Risk Factors in this report - "*The marketability of our production is dependent upon transportation and storage facilities and other facilities, most of which we do not control, and the availability of such transportation and storage capabilities, which have been severely limited by recent market conditions related to the COVID-19 pandemic and the current oversupply of oil and natural gas. If additional facilities do not become available, or, even if such facilities are available, but we are unable to access such facilities on commercially reasonable terms, our operations will likely be interrupted, our production could be curtailed, and our revenues reduced, among other consequences.*"

Our revenue, costs, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production, as well as the prices we pay for our natural gas purchases, which are affected by a variety of factors, including those discussed in Part II, Item 1A. "Risk Factors" in this Quarterly Report, as well as in Part I, Item 1A. "Risk Factors" in our Annual Report. Average oil prices were significantly lower for the three months ended March 31, 2020 compared to the three months ended December 31, 2019 and the three months ended March 31, 2019. Brent crude oil contract prices ranged from $68.91 per Bbl to $22.74 per Bbl during the first quarter of 2020. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. We have recently experienced an adverse widening in the price differential between Brent and California crude due to the lack of local demand and storage capacity. As described above, if storage availability does not increase in the near-term, oil prices may go materially lower and Brent and/or California pricing could potentially even become negative as WTI oil prices did on April 20, 2020. In California, the price we pay for fuel gas purchases is generally based on the Kern, Delivered Index, which was as high as $3.00 per MMBtu and as low as $1.29 per MMBtu during the first quarter of 2020, while we paid an average of $1.97 in this period.

The following table presents the average Brent, WTI, Kern, Delivered, and Henry Hub prices for the three months ended March 31, 2020, December 31, 2019 and March 31, 2019:

	Three Months Ended		
	March 31, 2020	**December 31, 2019**	**March 31, 2019**
Brent oil ($/Bbl)	$ 50.82	$ 62.42	$ 63.83
WTI oil ($/Bbl)	$ 46.35	$ 57.02	$ 54.87
Kern, Delivered natural gas ($/MMBtu)	$ 1.97	$ 2.99	$ 5.03
Henry Hub natural gas ($MMBtu)	$ 1.91	$ 2.40	$ 2.92

California oil prices are Brent-influenced as California refiners import approximately 70% of the state's demand from OPEC+ countries and other waterborne sources, primarily in the Middle East and South America. Without the higher costs associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, in appropriate oil price environments, should continue to allow us to realize positive cash margins in California over the cycle. However, even as Brent pricing has fallen due to demand destruction caused by the COVID-19 pandemic coupled with the OPEC+ supply surge, we have also experienced a widening in the price differential between Brent and the California benchmark, caused primarily by the lack of local demand and storage capacity. If California pricing remains weak, or declines further, our financial and operating results will be adversely affected.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for Utah's unique oil characteristics and the remoteness of the assets makes access to other markets logistically challenging.

Prices and differentials for NGLs are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products which are used as feedstock. In addition, infrastructure constraints magnify pricing volatility.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. We purchase substantially more natural gas for our steamfloods and cogeneration facilities than we produce and sell. Consequently, higher gas prices have a negative impact on our operating costs. However, we mitigate a portion of this exposure by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. We also strive to minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of such gas purchases. The negative impact of higher gas prices is partially offset by higher gas sales for the gas we produce.

Our earnings are also affected by the performance of our cogeneration facilities. These cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce operating expenses, we also sell electricity produced by three of our cogeneration facilities under long-term contracts with terms ending in July 1, 2021 through December 1, 2026. The most significant input and cost of the cogeneration facilities is natural gas. We generally receive significantly more revenue from these cogeneration facilities in the summer months, June through September, due to negotiated capacity payments we receive.

Seasonal weather conditions can impact our drilling and production activities. These seasonal conditions can occasionally pose challenges in our operations for meeting well-drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may have been and in the future may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild-fires and rain.

Additionally, like other companies in the oil and gas industry, our operations are subject to complex and stringent federal, state and local laws and regulations relating to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing, and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. For example, the jurisdiction, duties and enforcement authority of various state agencies have significantly increased with respect to oil and natural gas activities in recent years, and these state agencies as well as certain cities and counties have significantly revised their regulations, regulatory interpretations and data collection and reporting requirements and plan to issue additional regulations of certain oil and natural gas activities in 2020. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties. For additional information, please see Part I, Item 1 “Regulation of Health, Safety and Environmental Matters”, as well as Part I, Item 1.A. “Risk Factors” in our Annual Report.

How We Plan and Evaluate Operations

We use “Levered Free Cash Flow” in planning our capital allocation to sustain production levels and fund internal growth opportunities, as well as determine hedging needs. Levered Free Cash Flow is a non-GAAP financial measure that we define as Adjusted EBITDA less capital expenditures, interest expense, and dividends. Adjusted EBITDA is also a non- GAAP financial measure that is discussed and defined below.

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) operating expenses; (c) environmental, health & safety (“EH&S”) results; (d) general and administrative expenses; and (e) production.

Adjusted EBITDA

Adjusted EBITDA is the primary financial and operating measurement that our management uses to analyze and monitor the operating performance of our business. Adjusted EBITDA is a non-GAAP financial measure that we defined as earnings before interest expense; income taxes; depreciation, depletion, and amortization (“DD&A”); derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items.

Operating expenses

Overall, operating expense is used by management as a measure of the efficiency with which operations are performing.We define operating expenses as lease operating expenses, electricity generation expenses, transportation expenses, and marketing expenses, offset by the third-party revenues generated by electricity, transportation and marketing activities, as well as the effect of derivative settlements (received or paid) for gas purchases. Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Taxes other than income taxes are excluded from operating expenses. The electricity, transportation and marketing activity related revenues are viewed and treated internally as a reduction to operating costs when tracking and analyzing the economics of development projects and the efficiency of our hydrocarbon recovery. Additionally, we strive to minimize the variability of our fuel gas costs for our steam operations with gas hedges.

Environmental, health & safety

Like other companies in the oil and gas industry, our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Current and future laws and regulations, as well as legislative and regulatory changes and other government activities, can materially impact our exploration, development and production plans.

As part of our commitment to creating long-term stockholder value, we strive to conduct our operations in an ethical, safe and responsible manner, to protect the environment and to take care of our people and the communities in which we live and operate. We also seek proactive and transparent engagement with regulatory agencies, the communities in which we operate and our other stakeholders in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with existing laws and regulations. We monitor our EH&S performance through various measures, holding our employees and contractors to high standards.

General and administrative expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

Production

Oil and gas production is a key driver of our operating performance, an important factor to the success of our business, and used in forecasting future development economics. We measure and closely monitor production on a continuous basis, adjusting our property development efforts in accordance with the results. We track production by commodity type and compare it to prior periods and expected results.

Capital Expenditures

For the three months ended March 31, 2020, our capital expenditures were approximately $39 million, on an accrual basis including capitalized labor but excluding capitalized interest, acquisitions and asset retirement spending. Approximately 97% of this total was directed to California oil operations.

Toward the end of the first quarter we reduced our planned 2020 capital expenditures by approximately 50% from our original 2020 guidance in response to the sudden and significant oil and gas price deterioration caused by the COVID-19 pandemic and related economic repercussions, coupled with OPEC+ actions, which created significant volatility, uncertainty, and turmoil in the oil and gas industry. The updated capital expenditure guidance for 2020 is now approximately $65 million (inclusive of the $39 million spent in the first quarter), with approximately 65% of the capital spend weighted toward the first half of 2020. Our focus will be on the capital needed to sustain annual production levels for our California operations while continuing our permitting and proactive maintenance activities to support ongoing activity and safe operations. We proactively initiated an intense permitting program during the first quarter to ensure adequate inventory once we decide to begin our next drilling program. The updated capital budget assumes restarting one drilling rig no earlier than September 2020, primarily for sandstone development, if market conditions support the increase in activity. However, if we are unable to obtain sufficient storage and transportation capacity, or if these systems become unavailable to us on commercially reasonable terms or at all, we could be forced to shut in a significant amount of our California production, as well as potentially curtail some of our Utah and Colorado production beginning in the second quarter, which would eliminate a portion of our expected capital expenditures for the remainder of the year, including with respect to the drilling rig.

As discussed under “Business Environment, Market Conditions and Outlook” in this report, the U.S. is experiencing significant storage and transportation constraints, as a result of which refiners have started to curtail output and producers all over the world – including in the United States – have started to shut-in production. We are actively working to obtain sufficient storage and transportation capacity to support our planned production; however, if we are unable to do so, or if these systems become unavailable to us on commercially reasonable terms or at all, we could be forced to shut-in some or all of our production or delay or temporarily discontinue our drilling plans. Based on our current storage commitments, and assuming we are unable to obtain sufficient additional storage in the near term, we could be forced to shut-in a significant amount of our California production, as well as curtail some of our Utah and Colorado production, beginning in the second quarter, which could have a material, adverse effect on our financial and operational results. Whether and when we will have to reduce or shut-in production, and the extent to which we may have to do so, cannot be reasonably predicted at this time. However, should we significantly curtail or shut-in production, our expectations regarding our 2020 production, capital spend and capital development program will be affected and our previously issued guidance would not likely be achieved.

We currently expect year-over-year oil production growth in California to be flat to down 2% from 2019, which is consistent with our low corporate decline rates. We currently also anticipate oil production will be approximately 90% of total production in 2020, compared to 87% in 2019. Based on our current capital plan we expect to be able to fund our 2020 capital development programs with cash flow from operations. Even in this low price environment we plan to live within Levered Free Cash Flow through 2021 and beyond.

The amount and timing of capital expenditures are within our control and subject to our management’s discretion, and may be adjusted during the year depending on commodity prices, storage constraints, supply/demand considerations and other factors. We retain the flexibility to defer planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGLs, the receipt and timing of required regulatory permits and approvals, the availability of necessary equipment, infrastructure and capital, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners, as well as general market conditions. Additionally, for the full year 2020, we plan to spend approximately $15 million on plugging and abandonment activities, satisfying our obligations under the California-mandated Idle Well Management Plan.

Summary By Area

The following table shows a summary by area of our selected historical financial information and operating data for the periods indicated.

($ in thousands, except prices)	California (San Joaquin and Ventura basins) Three Months Ended March 31, 2020	December 31, 2019	March 31, 2019
Oil, natural gas and natural gas liquids sales	$ 109,519	$ 140,972	$ 111,896
Operating (loss) income[1]	$ (113,203)	$ 66,977	$ 48,572
Depreciation, depletion, and amortization (DD&A)	$ 30,918	$ 26,950	$ 21,342
Impairment of oil and gas properties	$ 163,879	$ —	$ —
Average daily production (MBoe/d)	24.9	25.5	21.0
Production (oil % of total)	100%	100%	100%
Realized sales prices:			
Oil (per Bbl)	$ 48.38	$ 60.20	$ 59.16
NGLs (per Bbl)	$ —	$ —	$ —
Gas (per Mcf)	$ —	$ —	$ —
Capital expenditures[2]	$ 38,072	$ 34,983	$ 42,509

($ in thousands, except prices)	Utah (Uinta basin) Three Months Ended March 31, 2020	December 31, 2019	March 31, 2019	Colorado (Piceance basin) Three Months Ended March 31, 2020	December 31, 2019	March 31, 2019
Oil, natural gas and natural gas liquids sales	$ 11,278	$ 13,618	$ 16,666	$ 1,299	$ 1,746	$ 2,540
Operating (loss) income[1]	$ (127,700)	$ 784	$ 4,268	$ 384	$ (51,356)	$ 593
Depreciation, depletion, and amortization (DD&A)	$ 4,311	$ 2,846	$ 2,930	$ 55	$ 262	$ 314
Impairment of oil and gas properties	$ 125,206	$ —	$ —	$ —	$ 51,081	$ —
Average daily production (MBoe/d)	4.5	4.4	5.2	1.4	1.4	1.6
Production (oil % of total)	53%	51%	59%	1%	1%	1%
Realized sales prices:						
Oil (per Bbl)	$ 39.64	$ 49.01	$ 41.37	$ 42.54	$ 51.87	$ 43.40
NGLs (per Bbl)	$ 13.16	$ 14.60	$ 24.56	$ —	$ —	$ —
Gas (per Mcf)	$ 2.22	$ 2.89	$ 4.59	$ 1.70	$ 2.23	$ 2.84
Capital expenditures[2]	$ 857	$ 4,282	$ 5,273	$ 6	$ 295	$ 40

(1) Operating (loss) income includes oil, natural gas and NGL sales, marketing revenues, other revenues, and scheduled oil derivative settlements, offset by operating expenses, general and administrative expenses, DD&A, impairment of oil and gas properties, and taxes, other than income taxes.

(2) Excludes corporate capital expenditures.

Production and Prices

The following table sets forth information regarding average daily production, total production and average prices for each of the periods indicated.

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
Average daily production:[1]			
Oil (MBbl/d)	27.3	27.7	24.1
Natural Gas (MMcf/d)	18.5	18.9	19.5
NGL (MBbl/d)	0.4	0.4	0.4
Total (MBoe/d)[2]	30.8	31.3	27.8
Total Production:			
Oil (MBbl)	2,485	2,553	2,170
Natural gas (MMcf)	1,684	1,737	1,752
NGLs (MBbl)	32	35	38
Total (MBoe)[2]	2,798	2,877	2,501
Weighted-average realized sales prices:			
Oil without hedges ($/Bbl)	$ 47.61	$ 59.28	$ 56.88
Oil with hedges ($/Bbl)	$ 57.28	$ 64.98	$ 62.03
Natural gas ($/Mcf)	$ 2.00	$ 2.60	$ 3.83
NGL ($/Bbl)	$ 13.16	$ 14.60	$ 24.35
Average Benchmark prices:			
Oil (Bbl) – Brent	$ 50.82	$ 62.42	$ 63.83
Oil (Bbl) – WTI	$ 46.35	$ 57.02	$ 54.87
Gas (MMBtu) – Kern, Delivered[3]	$ 1.97	$ 2.99	$ 5.03
Natural gas (MMBtu) – Henry Hub[4]	$ 1.91	$ 2.40	$ 2.92

(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(2) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the three months ended March 31, 2020, the average prices of Brent oil and Henry Hub natural gas were $50.82 per Bbl and $1.91 per MMBtu respectively, resulting in an oil-to-gas ratio of approximately 4 to 1 on an energy equivalent basis.

(3) Kern, Delivered Index is the relevant index used for gas purchases in California.

(4) Henry Hub is the relevant index used for gas sales in the Rockies.

The following table sets forth average daily production by operating area for the periods indicated:

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
Average daily production (MBoe/d):[1]			
California	24.9	25.5	21.0
Utah	4.5	4.4	5.2
Colorado	1.4	1.4	1.6
Total average daily production	30.8	31.3	27.8

(1) Production represents volumes sold during the period.

Average daily production, including sales of inventory, decreased 2% for the three months ended March 31, 2020, compared to the three months ended December 31, 2019, largely due to natural decline, partially offset by the impact of our development program in late December and into the first quarter of this year. Our California production of 24.9 MBoe/d for the first quarter of 2020 decreased 2% from the fourth quarter of 2019.

In the first quarter of 2020 a significant portion of our capital expenditures was used for activities which have no impact on current production, including approximately 50% of such costs for facilities, equipping and permitting for future development. Of the 19 wells drilled in the first quarter, nine were delineation and two were injector wells, while eight were producing wells. We also expended approximately $4 million for plugging and abandonment activities.

Average daily production volumes increased 11% for the three months ended March 31, 2020 as compared to the three months ended March 31, 2019 due to production response from development capital spending throughout 2018 and 2019, which offset the natural decline of our properties. Production increased 18% in California, where the substantial majority of our development capital was deployed, for the three months ended March 31, 2020 compared to the same period in 2019. This increase strongly demonstrated the ability of our California properties to respond to capital and perform as expected. The production in Utah and Colorado decreased 13% for the three months ended March 31, 2020 compared to the same period in 2019. The overall decrease was primarily due to a lack of capital expenditures and natural decline.

Results of Operations

Three Months Ended March 31, 2020 compared to Three Months Ended December 31, 2019.

	Three Months Ended			
	March 31, 2020	December 31, 2019	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 122,098	$ 156,336	$ (34,238)	(22)%
Electricity sales	5,461	6,844	(1,383)	(20)%
Gain (losses) on oil derivatives	211,229	(45,544)	256,773	n/a
Marketing and other revenues	477	492	(15)	(3)%
Total revenues and other	$ 339,265	$ 118,128	$ 221,137	187 %

Revenues and Other

Oil, natural gas and NGL sales decreased by $34 million, or 22%, to approximately $122 million for the three months ended March 31, 2020, compared to the three months ended December 31, 2019. The decrease was driven by $29 million of lower oil prices, $4 million of lower oil volume, and $1 million of lower gas prices.

Electricity sales represent sales to utilities, and decreased $1 million, or 20%, to approximately $5 million for the three months ended March 31, 2020 compared to the three months ended December 31, 2019. The decrease was mostly due to lower unit sales prices that were driven by lower natural gas pricing, and partially offset by higher unit sales resulting from lower downtime.

Gains on oil derivatives were approximately $211 million, including settlement gains of $24 million, for the three months ended March 31, 2020, compared to a loss of approximately $46 million that included $15 million of settlement gains for the three months ended December 31, 2019. Settlement gains reflect the positions that expired during the period with hedge strike prices above the respective index prices. The quarter-over-quarter increase in the settled gains was predominantly due to the larger spread between the average hedge strike prices and the index prices in the quarter ended March 31, 2020 than in the prior quarter. During 2020, the decrease in index prices relative to our remaining hedge positions at period-end resulted in increased value, resulting in mark-to-market gains in 2020, while the opposite effect occurred in the fourth quarter of 2019.

Marketing and other revenues were comparable for the three months ended March 31, 2020 and the three months ended December 31, 2019. Marketing revenues in these periods represented sales of natural gas purchased from third parties.

	Three Months Ended			
	March 31, 2020	December 31, 2019	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 50,752	$ 59,529	$ (8,777)	(15)%
Electricity generation expenses	3,946	4,785	(839)	(18)%
Transportation expenses	1,822	2,124	(302)	(14)%
Marketing expenses	430	403	27	7 %
General and administrative expenses	19,337	15,710	3,627	23 %
Depreciation, depletion and amortization	35,329	30,102	5,227	17 %
Impairment of oil and gas properties	289,085	51,081	238,004	466 %
Taxes, other than income taxes	4,352	11,962	(7,610)	(64)%
Losses (gains) on natural gas derivatives	12,035	(3,385)	15,420	n/a
Other operating expenses	2,202	774	1,428	184 %
Total expenses and other	419,290	173,085	246,205	142 %
Other (expenses) income:				
Interest expense	(8,920)	(7,871)	(1,049)	13 %
Other, net	(6)	—	(6)	100 %
Loss before income taxes	(88,951)	(62,828)	(26,123)	(42)%
Income tax expense (benefit)	26,349	(55,844)	82,193	147 %
Net loss	$ (115,300)	$ (6,984)	$ (108,316)	(1,551)%
Expenses per Boe:[1]				
Lease operating expenses	$ 18.14	$ 20.69	$ (2.55)	(12)%
Electricity generation expenses	1.41	1.66	(0.25)	(15)%
Electricity sales[1]	(1.95)	(2.38)	0.43	(18)%
Transportation expenses	0.65	0.74	(0.09)	(12)%
Transportation sales[1]	(0.01)	(0.02)	0.01	(50)%
Marketing expenses	0.15	0.14	0.01	7 %
Marketing revenues[1]	(0.16)	(0.15)	(0.01)	7 %
Derivatives settlements paid (received) for gas purchases[1]	1.58	(0.31)	1.89	(610)%
Total operating expenses	$ 19.81	$ 20.37	$ (0.56)	(3)%
Total unhedged operating expenses[2]	$ 18.23	$ 20.68	$ (2.45)	(12)%
Total non-energy operating expenses[4]	$ 14.03	$ 14.96	$ (0.93)	(6)%
Total energy operating expenses[5]	$ 5.78	$ 5.41	$ 0.37	7 %
General and administrative expenses[3]	$ 6.91	$ 5.46	$ 1.45	27 %
Depreciation, depletion and amortization	$ 12.63	$ 10.46	$ 2.17	21 %
Taxes, other than income taxes	$ 1.56	$ 4.16	$ (2.60)	(63)%

(1) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing revenues and expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also include the effect of derivative settlements (received or paid) for gas purchases.

(2) Total unhedged operating expenses equals total operating expenses, excluding the derivative settlements paid (received) for gas purchases.

(3) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.71 per Boe and $0.80 per Boe for the three months ended March 31, 2020 and December 31, 2019, respectively.

(4) Total non-energy operating expenses equals total operating expenses, excluding fuel, electricity sales and gas purchase derivative settlement (gains) losses.

(5) Total energy operating expenses equals fuel and gas purchase derivative settlement (gains) losses less electricity sales.

Expenses and Other

In accordance with GAAP, we report sales of electricity, marketing and transportation activities (as applicable) separately in our financial statements as revenues. However, these revenues are viewed and used internally in calculating operating expenses, which are used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery.

Operating expenses are defined above in “How We Plan and Evaluate Operations”. On an unhedged basis, operating expenses decreased by $2.45 per Boe to $18.23 for the first quarter 2020, compared to $20.68 for the fourth quarter 2019. The decrease was driven by $2.55 per Boe lower lease operating expenses. Additionally, operating expenses, including hedge effects, decreased to $19.81 per Boe in the first quarter 2020 from $20.37 in the fourth quarter 2019 due to the same factors and $1.89 per Boe higher settlement gas hedge losses period-over-period.

Lease operating expenses per Boe decreased to $18.14 for the three months ended March 31, 2020, compared to $20.69 per Boe for the three months ended December 31, 2019 driven by lower unhedged fuel costs related to our California steam operations. Unhedged fuel cost decreased $1.96 per Boe, or 24% in the first quarter 2020 from $8.11 for the three months ended December 31, 2019. Additionally, certain non-energy lease operating expenses decreased by approximately $1.00 per Boe, including well, lease and facility repair and maintenance activity, power costs and chemicals. These decreases were partially offset by approximately $0.50 per Boe of higher expenses related to company labor and inventory sales. Lease operating expenses includes fuel, maintenance, labor including supervision, vehicles, workover expenses, field office, and tools and supplies. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses decreased approximately 15% to $1.41 per Boe for the three months ended March 31, 2020, compared to $1.66 per Boe for the three months ended December 31, 2019 mostly due to lower natural gas costs described above. These fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Losses on natural gas derivatives of $12 million for the three months ended March 31, 2020, consisted of $8 million of mark-to-market valuation losses and $4 million of settlement derivative contract losses, due to low gas prices. The $3 million gain on natural gas derivatives for the three months ended December 31, 2019 consisted of $2 million of mark-to-market valuation gains and $1 million of settlement contract gains. Quarter-over-quarter losses and gains were the result of changes between gas prices relative to the fixed prices of our derivative contracts.

Transportation expenses decreased 12% to $0.65 per Boe for the three months ended March 31, 2020 from $0.74 per Boe for the three months ended December 31, 2019 mostly due to lower volumes shipped.

Marketing expenses were flat for the three months ended March 31, 2020 and December 31, 2019. Marketing expenses in these periods, which exclude the effects of hedging, represented the cost of natural gas purchased from third parties.

General and administrative expenses increased by $3.6 million, or 23%, to approximately $19 million for the three months ended March 31, 2020, compared to the three months ended December 31, 2019. For the three months ended

March 31, 2020 and December 31, 2019, general and administrative expenses included certain non-recurring costs of approximately $1.9 million and $0, respectively, and non-cash stock compensation costs of approximately $2.9 million and $2.3 million, respectively. The first quarter 2020 non-recurring costs mainly consisted of credit-related charges in connection with the significantly deteriorated price environment. Further differences in general and administrative expenses between these periods are noted below.

Adjusted general and administrative expenses, which exclude non-recurring costs and non-cash stock compensation costs, were $15 million or $5.20 per Boe for the first quarter 2020 compared to $13 million or $4.66 per Boe for the fourth quarter 2019. Please see “-Non-GAAP Financial Measures” for a reconciliation of adjusted general and administrative expense to general and administrative expenses, the most directly comparable financial measures calculated and presented in accordance with GAAP. The increase in adjusted general and administrative expenses was primarily due to higher accrued annual performance incentive costs in 2020 compared to the fourth quarter 2019 as prior year performance targets were not fully met. The first quarter 2020 does not incorporate any of our general and administrative expense reduction previously announced.

DD&A increased by $5 million or 17% to approximately $35 million for the three months ended March 31, 2020 compared to the three months ended December 31, 2019. On a per Boe basis, period-over-period DD&A increased $2.17 or 21% due to higher 2020 depreciation and depletion rates resulting from the significant capital development program in 2019.

Impairment of oil and gas properties

At March 31, 2020, we performed impairment tests with respect to our proved and unproved oil and gas properties as a result of significant declines in oil prices during the latter part of the first quarter. These declines were driven by the uncertainty surrounding the outbreak of novel strain of coronavirus (SARS-Cov-2), which causes COVID-19 (“COVID-19”) and other macroeconomic events such as the geopolitical tensions between OPEC and Russia. The COVID-19 pandemic and related economic repercussions, coupled with OPEC+ actions, created significant volatility, uncertainty, and turmoil in the oil and gas industry, which have negatively affected and are expected to continue to negatively affect our business. Low oil prices are expected to continue for some period as reflected by current futures forward curves for crude.

Consequently, we recorded a non-cash pre-tax asset impairment charge of $289 million on properties in Utah and certain California locations. We evaluate our proved properties in accordance with accounting guidance and fair value techniques utilizing the period-end forward price curve, as well as assessing projects we determine we would not pursue in the foreseeable future given the current environment. We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our unproved property balance at March 31, 2020.

For the fourth quarter of 2019, we evaluated our proved and unproved natural gas properties in regards to the decline in our expectations of future gas prices. As a result, we recorded a non-cash pre-tax asset impairment charge of $51 million for our Piceance gas properties in Colorado, of which $23 million was for proved properties and $28 million for unproved properties.

Taxes, Other Than Income Taxes

	Three Months Ended			
	March 31, 2020	December 31, 2019	$ Change	% Change
	(in thousands)			
Severance taxes	$ 0.72	$ 0.78	$ (0.06)	(8)%
Ad valorem and property taxes	1.38	1.55	(0.17)	(11)%
Greenhouse gas allowances	(0.54)	1.83	(2.37)	(130)%
Total taxes other than income taxes	$ 1.56	$ 4.16	$ (2.60)	(63)%

Taxes, other than income taxes, decreased in the three months ended March 31, 2020 by $2.60 per Boe, or 63%, to $1.56 due to lower greenhouse gas allowance spot prices resulting in reductions to cumulative emission costs to date which are scheduled for payment in future periods.

Other operating expenses

Other operating expenses increased approximately $1 million to $2 million in the three months ended March 31, 2020 from $1 million in the three months ended December 31, 2019. The increase mostly included excess abandonment costs in the first quarter and drilling rig standby costs due to deferred drilling activity.

Interest Expense

Interest expense increased in the three months ended March 31, 2020 by $1 million, or 13%, due to higher borrowings during the first quarter of 2020 compared to the fourth quarter of 2019.

Income Tax Expense (Benefit)

Our effective tax rate was approximately (30%) and 89% for the three months ended March 31, 2020 and December 31, 2019, respectively. The rate in 2020 was negatively impacted as we have recorded a valuation allowance on a large portion of our interest deduction carryforwards and tax credits due to changes during the quarter related to future realizability. The rate in the fourth quarter 2019 reflects the recognition of US federal general business credits which were related to 2017 and 2018 tax periods. These credits are available to offset future federal income tax liabilities.

Three Months Ended March 31, 2020 compared to Three Months Ended March 31, 2019.

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019	$ Change	% Change
		(in thousands)		
Revenues and other:				
Oil, natural gas and NGL sales	$ 122,098	$ 131,102	$ (9,004)	(7)%
Electricity sales	5,461	9,729	(4,268)	(44)%
Gain (losses) on oil derivatives	211,229	(65,239)	276,468	n/a
Marketing and other revenues	477	947	(470)	(50)%
Total revenues and other	$ 339,265	$ 76,539	$ 262,726	343 %

Revenues and Other

Oil, natural gas and NGL sales decreased by $9 million, or 7% to approximately $122 million for the three months ended March 31, 2020 when compared to the three months ended March 31, 2019. The decrease was mostly driven by $23 million of lower oil prices and $3 million lower gas prices. These decreases were partially offset by $18 million of higher oil volumes.

Electricity sales represent sales to utilities which decreased by $4 million, or 44%, to approximately $5 million for the three months ended March 31, 2020 when compared to the three months ended March 31, 2019. The decrease was due to lower unit sales prices that were impacted by lower natural gas prices described above.

Gains on oil derivatives were approximately $211 million, including settlement gains of $24 million for the three months ended March 31, 2020, compared to a loss of approximately $65 million for the three months ended March 31, 2019, that consisted of $76 million mark-to-market valuation loss and $11 million settlement gains. During 2020, the change in Brent prices relative to our remaining positions at quarter end resulted in increased value.

Marketing and other revenues were lower for the three months ended March 31, 2020, compared to the three months ended March 31, 2019 due to lower average gas prices. Marketing revenues in these periods represented sales of natural gas purchased from third parties.

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	Three Months Ended March 31, 2020	2019	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 50,752	$ 57,928	$ (7,176)	(12)%
Electricity generation expenses	3,946	7,760	(3,814)	(49)%
Transportation expenses	1,822	2,173	(351)	(16)%
Marketing expenses	430	851	(421)	(49)%
General and administrative expenses	19,337	14,340	4,997	35 %
Depreciation, depletion and amortization	35,329	24,585	10,744	44 %
Impairment of oil and gas properties	289,085	—	289,085	100 %
Taxes, other than income taxes	4,352	8,086	(3,734)	(46)%
Losses (gains) on natural gas derivatives	12,035	(2,115)	14,150	n/a
Other operating expenses	2,202	1,245	957	77 %
Total expenses and other	419,290	114,853	304,437	265 %
Other (expenses) income:				
Interest expense	(8,920)	(8,805)	(115)	1 %
Other, net	(6)	154	(160)	(104)%
Reorganization items, net	—	(231)	231	(100)%
Loss before income taxes	(88,951)	(47,196)	(41,755)	(88)%
Income tax expense (benefit)	26,349	(13,098)	39,447	301 %
Net loss	$ (115,300)	$ (34,098)	$ (81,202)	(238)%
Expenses per Boe:[1]				
Lease operating expenses	$ 18.14	$ 23.16	$ (5.02)	(22)%
Electricity generation expenses	1.41	3.10	(1.69)	(55)%
Electricity sales[1]	(1.95)	(3.89)	1.94	(50)%
Transportation expenses	0.65	0.87	(0.22)	(25)%
Transportation sales[1]	(0.01)	(0.05)	0.04	(80)%
Marketing expenses	0.15	0.34	(0.19)	(56)%
Marketing revenues[1]	(0.16)	(0.33)	0.17	(52)%
Derivatives settlements paid (received) for gas purchases[1]	1.58	(1.49)	3.07	206 %
Total operating expenses	$ 19.81	$ 21.71	$ (1.90)	(9)%
Total unhedged operating expenses[2]	$ 18.23	$ 23.20	$ (4.97)	(21)%
Total non-energy operating expenses[4]	$ 14.03	$ 14.68	$ (0.65)	(4)%
Total energy operating expenses[5]	$ 5.78	$ 7.04	$ (1.26)	(18)%
General and administrative expenses[3]	$ 6.91	$ 5.73	$ 1.18	21 %
Depreciation, depletion and amortization	$ 12.63	$ 9.83	$ 2.80	28 %
Taxes, other than income taxes	$ 1.56	$ 3.23	$ (1.67)	(52)%

(1) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing revenues and expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to date. Operating expenses also include the effect of derivative settlements (received or paid) for gas purchases.

(2) Total unhedged operating expenses equals total operating expenses, excluding the derivative settlements paid (received) for gas purchases.

(3) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.71 per Boe and $1.10 per Boe for the three months ended March 31, 2020 and March 31, 2019, respectively.

(4) Total non-energy operating expenses equals total operating expenses, excluding fuel, electricity sales and gas purchase derivative settlement (gains) losses.

(5) Total energy operating expenses equals fuel and gas purchase derivative settlement (gains) losses less electricity sales.

Expenses and Other

Operating expenses, on an unhedged basis were $7 million, or $4.97 per Boe, lower for the three months ended March 31, 2020 compared to the three months ended March 31, 2019. This decrease included $5.02 per Boe lower lease operating expenses and $0.22 lower transportation expenses, partially offset by $0.25 increase from the net changes in electricity sales and expenses. Additionally, operating expenses, including hedge effects, decreased to $19.81 per Boe for the first quarter 2020 from $21.71 per Boe for the first quarter 2019 due to these same factors and $3.07 per Boe of settlement gas hedge loss impact.

Lease operating expenses were $18.14 per Boe for the three months ended March 31, 2020, compared to $23.16 for the three months ended March 31, 2019, driven primarily by lower fuel prices related to our California steam operations. Fuel cost decreased $6.27 per Boe during the first quarter 2020 from $12.42 in the same period of 2019 as natural gas prices declined 52%. Lease operating expenses also included $0.73 per Boe higher lease and facility maintenance and $0.41 higher chemicals driven by increased volume processing compared to the three months ended March 31, 2019. Fuel costs excluded the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses decreased approximately 55% to $1.41 per Boe for the three months ended March 31, 2020 from $3.10 per Boe for the same period in 2019 primarily driven by lower fuel cost as mentioned above. Decreased fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements discussed elsewhere.

Losses on natural gas derivatives of $12 million for the three months ended March 31, 2020 consisted of $4 million in losses on settlement derivative contracts and $8 million in mark-to-market valuation losses. Gains on natural gas derivatives of $2 million for the three months ended March 31, 2019 consisted of $4 million in gains on settlement derivative contracts and $2 million in mark-to-market valuation losses.

Transportation expenses decreased 25% to $0.65 per Boe for the three months ended March 31, 2020, compared to $0.87 per Boe for the three months ended March 31, 2019, mainly due to lower volumes shipped from our Rockies assets.

Marketing expenses decreased 56% to $0.15 per Boe for the three months ended March 31, 2020, compared to $0.34 per Boe for the three months ended March 31, 2019 due to lower gas prices. Marketing expenses in these periods, which exclude the effects of hedging, represented the cost of natural gas purchased from third parties.

General and administrative expenses increased by approximately $5 million, or 35%, to approximately $19 million for the three months ended March 31, 2020 compared to the three months ended March 31, 2019. For the three months ended March 31, 2020 and March 31, 2019, general and administrative expenses also included non-recurring costs of approximately $1.9 million and $1.3 million, respectively, and non-cash stock compensation costs of approximately $2.9 million and $1.4 million, respectively.

Adjusted general and administrative expenses, which exclude non-recurring costs and non-cash stock compensation costs, were $15 million or $5.20 per Boe for the three months ended March 31, 2020 compared to $12 million or $4.63

per Boe for the three months ended March 31, 2019. The year-over-year increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the company's growth, including the expansion of our corporate affairs department and activities whose purpose is to support our efforts and participation in the regulatory, political and legislative process primarily in California.

DD&A increased $11 million, or 44%, to approximately $35 million for the three months ended March 31, 2020 compared to the three months ended March 31, 2019, primarily due to the increased production and higher depreciation and depletion rates for 2020. On a per Boe basis, period-over-period DD&A increased $2.80 to $12.63 from $9.83 due to capital development program.

Impairment of oil and gas properties

As discussed above, we recorded a non-cash pre-tax asset impairment charge of $289 million on properties in Utah and certain California locations. We evaluate our proved properties in accordance with accounting guidance and fair value techniques utilizing the period-end forward price curve, as well as assessing projects we determine we would not pursue in the foreseeable future given the current environment.

Taxes, Other Than Income Taxes

	Three Months Ended March 31,			
	2020	2019	$ Change	% Change
	(in thousands)			
Severance taxes	$ 0.72	$ 0.28	$ 0.44	157 %
Ad valorem and property taxes	1.38	1.26	0.12	10 %
Greenhouse gas allowances	(0.54)	1.69	(2.23)	(132)%
Total taxes other than income taxes	$ 1.56	$ 3.23	$ (1.67)	(52)%

Taxes, other than income taxes decreased 52% to $1.56 per Boe for the three months ended March 31, 2020 compared to $3.23 per Boe for the three months ended March 31, 2019. This decrease was largely due to lower greenhouse gas allowance spot prices resulting in reductions to cumulative emission costs to date which are scheduled for payment in future periods.

Severance tax refunds received during the first quarter 2019, related to prior periods, decreased the related expense compared to 2020.

Other operating expenses

Other operating expense, which largely consisted of excess abandonment costs and drilling rig standby costs due to deferred drilling activity, increased by $1 million to approximately $2 million for the three months ended March 31, 2020.

Interest Expense

Interest expense was comparable in the three months ended March 31, 2020 and March 31, 2019.

Reorganization items, net

Reorganization items, net were not material for the three months ended March 31, 2020 and March 31, 2019.

Income Tax Expense (Benefit)

Our effective tax rate was (30%) and 28% for the three months ended March 31, 2020 and March 31, 2019, respectively. The rate in 2020 was negatively impacted as we have recorded a valuation allowance on a large portion of our interest deduction carryforwards and tax credits recorded in 2019 as a result of changes during the quarter related to future realizability.

Non-GAAP Financial Measures

Adjusted EBITDA, Levered Free Cash Flow and Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses

Adjusted Net Income (Loss) is not a measure of net income (loss), Levered Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow are supplemental non-GAAP financial measures used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends.

Our management believes Adjusted EBITDA provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and the investment community. The measure also allows our management to more effectively evaluate our operating performance and compare the results between periods without regard to our financing methods or capital structure. Levered Free Cash Flow is used by management as a primary metric to plan capital allocation to sustain production levels and for internal growth opportunities, as well as hedging needs. It also serves as a measure for assessing our financial performance and our ability to generate excess cash from operations to service debt and pay dividends.

Adjusted Net Income (Loss) excludes the impact of unusual, out-of-period and infrequent items affecting earnings that vary widely and unpredictably, including non-cash items such as derivative gains and losses. This measure is used by management when comparing results period over period. We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate.

While Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Our computations of Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Net Income (Loss) and Levered Free Cash Flow should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

Adjusted General and Administrative Expenses is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense. Management believes

Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period.

We exclude the items listed above from general and administrative expenses in arriving at Adjusted General and Administrative Expenses because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature. Adjusted General and Administrative Expenses should not be considered as an alternative to, or more meaningful than, general and administrative expenses as determined in accordance with GAAP. Our computations of Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures of other companies.

The following tables present reconciliations of the non-GAAP financial measures Adjusted EBITDA and Levered Free Cash Flow to the GAAP financial measures of net income (loss) and net cash provided or used by operating activities, as applicable, for each of the periods indicated.

	Three Months Ended		
	March 31, 2020	**December 31, 2019**	**March 31, 2019**
		(in thousands)	
Adjusted EBITDA reconciliation to net income (loss):			
Net loss	$ (115,300)	$ (6,984)	$ (34,098)
Add (Subtract):			
Interest expense	8,920	7,871	8,805
Income tax expense (benefit)	26,349	(55,845)	(13,098)
Depreciation, depletion and amortization	35,329	30,102	24,585
Impairment of oil and gas properties	289,085	51,081	—
Derivative (gains) losses	(199,194)	42,160	63,124
Net cash received for scheduled derivative settlements	19,625	15,466	14,904
Other operating expenses	2,202	774	1,245
Stock compensation expense	2,922	2,370	1,475
Non-recurring costs	1,862	—	1,329
Reorganization items, net	—	—	231
Adjusted EBITDA	$ 71,800	$ 86,995	$ 68,502

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
	(in thousands)		
Adjusted EBITDA and Levered Free Cash Flow reconciliation to net cash provided by (used in) operating activities:			
Net cash provided by operating activities	$ 44,483	$ 86,036	$ 21,097
Add (Subtract):			
Cash interest payments	14,879	584	14,000
Cash income tax payments (refunds)	2	(3)	—
Non-recurring costs	1,862	—	1,329
Other changes in operating assets and liabilities	10,574	378	32,076
Adjusted EBITDA	$ 71,800	$ 86,995	$ 68,502
Subtract:			
Capital expenditures - accrual basis	(39,415)	(41,877)	(49,099)
Interest expense	(8,920)	(7,871)	(8,805)
Cash dividends declared	(9,564)	(9,552)	(10,072)
Levered Free Cash Flow[(1)]	$ 13,901	$ 27,695	$ 526

(1) Levered Free Cash Flow, as defined by the Company, includes cash received for scheduled derivative settlements of $20 million, $15 million and $15 million in the three months ended March 31, 2020, December 31, 2019 and March 31, 2019, respectively.

The following table presents a reconciliation of the non-GAAP financial measure Adjusted Net Income (Loss) to the GAAP financial measure of net income (loss).

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
	(in thousands)		
Adjusted Net Income (Loss) reconciliation to net income (loss):			
Net loss	$ (115,300)	$ (6,984)	$ (34,098)
Add (Subtract): discrete income tax items	46,700	(38,653)	—
Add (Subtract):			
(Gains) losses on oil and natural gas derivatives	(199,194)	42,159	63,124
Net cash received for scheduled derivative settlements	19,625	15,466	14,904
Other operating expenses	2,202	774	1,245
Impairment of oil and gas properties	289,085	51,081	—
Non-recurring costs	1,862	—	1,329
Reorganization items, net	—	—	231
Total additions, net	113,580	109,480	80,833
Income tax expense of adjustments at effective tax rate[(1)]	(26,805)	(30,654)	(22,471)
Adjusted Net Income (Loss)	$ 18,175	$ 33,189	$ 24,264

(1) Excludes prior year income tax credits from the total additions, net line item and the tax effect the prior tax credits have on the current year effective tax rate.

The following table presents a reconciliation of the non-GAAP financial measure Adjusted General and Administrative Expenses to the GAAP financial measure of general and administrative expenses for each of the periods indicated.

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
	(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:			
General and administrative expenses	$ 19,337	$ 15,710	$ 14,340
Subtract:			
Non-recurring costs	(1,862)	—	(1,329)
Non-cash stock compensation expense (G&A portion)	(2,919)	(2,289)	(1,424)
Adjusted G&A	$ 14,556	$ 13,421	$ 11,587
Adjusted general and administrative expenses ($/MBoe)	$ 5.20	$ 4.66	$ 4.63

Liquidity and Capital Resources

Currently, we expect our primary sources of liquidity and capital resources will be Levered Free Cash Flow, and as needed, borrowings under the RBL Facility, described below. As of March 31, 2020, we had minimal cash and available borrowings of $382 million under our RBL Facility. We currently believe that our liquidity and capital resources will be sufficient to conduct our business and operations for the next 12 months.

We currently expect our operations to continue to generate positive Levered Free Cash Flow, even at the currently depressed commodity price levels, through 2020 and into 2021 given our current hedge positions and based on our current operating plans. We have nearly 100% of our expected California oil production hedged in 2020 at nearly $60 per barrel, as well as additional 2021 hedge positions at $47.19 per barrel for 9,000 barrels per day. As of March 31, 2020, our oil hedge positions had a fair value of approximately $194 million. However, our business, like other producers, has been and is expected to continue to be negatively affected by the ongoing and evolving volatility, uncertainty, and turmoil in the oil and gas industry created by the COVID-19 demand destruction and the supply surge from OPEC+'s actions, notably by Saudi Arabia and Russia as further discussed under "Business Environment, Market Conditions and Outlook" in this report. In terms of immediate risks, if we were forced to shut-in a significant amount of our California production, as well as curtail some of our Utah and Colorado production, this could have a material, adverse effect on our financial and operational results. If we are forced to shut in production, we will incur additional costs to bring those associated wells back online, as well as additional costs and operating expenses while production is shut-in to, among other things, maintain the health of the reservoirs, meet contractual obligations and protect our interests, but without the associated revenue. Additionally, depending on the duration of the shut-in, and whether we also need to shut-in steam injection for the reservoirs rather than incur those costs, the wells may not, initially or at all, come back online at similar rates to those at the time of shut-in. Depending on the duration of the steam injection shut-in time, and the resulting inefficiency and economics of restoring the reservoir to its energetic and heated state, our proved reserve estimates could decrease, which could result in a reduction to our borrowing base under the RBL Facility and our liquidity.

In the longer term, if these extremely depressed oil prices were to persist through 2021 and longer as currently predicted by the forward curve for oil, we may not be able to continue to generate Levered Free Cash Flow and our liquidity and capital resources may not be sufficient to conduct our business and operations for the longer term until commodity prices recover. In light of industry downturn and continuing uncertainty, negative commodity price outlook, and significant risks mentioned above and further discussed elsewhere in this report (including under Part II, Item 1.A. "Risk Factors", which we urge you to read), our strategy to survive the next two years is focused on preserving cash, reducing costs and maintaining business continuity. We have significantly reduced planned 2020 capital expenditures and non-employee general and administrative expenses and are focused on improving operational efficiencies. We also temporarily suspended our quarterly cash dividend, starting with the second quarter of 2020, and year-to-date we have not repurchased any common stock under our authorized share repurchase program. As mentioned above, we enhanced our hedge positions for 2020, and to a lesser extent for 2021. Depending on the timing and rate of the eventual recovery and our outlook, we may potentially use Levered Free Cash Flow generated this year to opportunistically repurchase our bonds to strengthen our balance sheet to withstand an extended low commodity price environment, to explore accretive acquisitions that would strengthen our asset base or to fund our 2021 capital expenditures in the event there is a shortfall next year. Although we continue to actively work to mitigate the evolving challenges of this severe industry downturn on our operations, our financial condition and our employees and contractors, there is no certainty that the measures we take will be ultimately sufficient. We are unable to reasonably predict when, or to what extent, commodity prices and the overall markets and global economy will stabilize, and the pace of any subsequent recovery for the oil and gas industry. Further, to what extent these events do ultimately impact our business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous evolving factors that cannot be predicted, including the duration of the COVID-19 pandemic and future actions by OPEC+.

The RBL Facility

On July 31, 2017, we entered into a credit agreement providing for a revolving loan with up to $1.5 billion of commitments, subject to a reserve borrowing base ("RBL Facility"), which is further discussed in Note 2 - Debt to the Notes to the Condensed Consolidated Financial Statements in Part I of this report. As of March 31, 2020 the elected commitment of our borrowing base was $400 million and we had approximately $11 million in borrowings outstanding, $7 million in letters of credit outstanding, and approximately $382 million available for borrowing under the RBL Facility. In late 2019, we completed a borrowing base redetermination under our RBL Facility that set our borrowing base to $500 million and reaffirmed our elected commitment amount at $400 million. Borrowing base redeterminations generally become effective each May and November, although each of us and the administrative agent may make one interim redetermination between scheduled redeterminations. While we have submitted our most recent borrowing base redetermination, we have not yet received the results.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. If we do not comply with the financial and other covenants in the RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Facility and exercise all of their other rights and remedies, including foreclosure on all of the collateral.

The RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a Leverage Ratio of no more than 4.0 to 1.0 and (ii) a Current Ratio of at least 1.0 to 1.0. The RBL Facility also contains customary restrictions. As of March 31, 2020, our Leverage Ratio and Current Ratio were 1.4 to 1.0 and 4.2 to 1.0, respectively. In addition, the RBL Facility currently provides that to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the RBL Facility as of March 31, 2020.

Hedging

We have protected substantially all of our anticipated cash flows in 2020, as well as a significant portion in 2021, using our commodity hedging program, including through fixed-price derivative contracts. We hedge crude oil production to protect against oil price decreases and we also hedge gas purchases to protect against price increases. For information regarding risks related to our hedging program, see “Item 1A. Risk Factors—Risks Related to Our Business and Industry” in our Annual Report.

As of March 31, 2020, we had the following crude oil production and gas purchases hedges.

	Q2 2020	Q3 2020	Q4 2020	FY 2021
Fixed Price Oil Swaps (Brent):				
Hedged volume (MBbls)	2,184	2,208	2,208	3,282
Weighted-average price ($/Bbl)	$ 59.91	$ 59.85	$ 59.85	$ 47.19
Fixed Price Oil Swaps (WTI):				
Hedged volume (MBbls)	30	—	—	—
Weighted-average price ($/Bbl)	$ 61.75	$ —	$ —	$ —
Purchased Oil Calls Options (Brent):				
Hedged volume (MBbls)	273	276	276	—
Weighted-average price ($/Bbl)	$ 65.00	$ 65.00	$ 65.00	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	5,005,000	5,060,000	3,840,000	8,500,000
Weighted-average price ($/MMBtu)	$ 2.89	$ 2.89	$ 2.73	$ 2.62
Fixed Price Gas Purchase Swaps (SoCal Citygate):				
Hedged volume (MMBtu)	455,000	460,000	155,000	—
Weighted-average price ($/MMBtu)	$ 3.80	$ 3.80	$ 3.80	$ —

In April 2020, we added fixed price gas purchase swaps (Kern, Delivered) of 10,000 MMbtu/d at $2.79 beginning November 2020 through October 2021.

The following table summarizes the historical results of our hedging activities.

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
Crude Oil (per Bbl):			
Realized sales price, before the effects of derivative settlements	$ 47.61	$ 59.28	$ 56.88
Effects of derivative settlements	$ 9.67	$ 5.70	$ 5.15
Natural Gas (per MMBtu):			
Purchase price, before the effects of derivative settlements	$ 2.33	$ 3.22	$ 4.87
Effects of derivative settlements	$ 0.60	$ (0.12)	$ (0.59)

We expect our operations to generate sufficient cash flows at current commodity prices including our 2020 and 2021 hedging positions. Our generally low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production.

Cash Dividends

Our Board of Directors approved $0.12 per share quarterly cash dividend on our common stock for the first quarter of 2020, which we paid in April 2020. However, in April 2020, in connection with the current low oil price environment, we temporarily suspended our quarterly dividend until oil prices recover. As of April 30, 2020, the Company has paid approximately $65 million in dividends, since the inception of its dividend program in the third quarter of 2018.

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock at that time, they authorized initial repurchases of up to $50 million under the program. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. We are not required or otherwise obligated to repurchase any additional shares during any period or at all, and any repurchases may be commenced or suspended at any time without notice. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors. Any shares acquired under this repurchase program will be available for general corporate purposes. The Company has repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million as of December 31, 2019. For the three months ended March 31, 2020, we did not repurchase any shares under the stock repurchase program.

Bond Repurchase Program

In February 2020, our Board of Directors adopted a program to spend up to $75 million of our unsecured notes due February 2026 (the "2026 Notes"). The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors. We are not required or otherwise obligated to repurchase any of the 2026 Notes during any period or at all, and any repurchases may be commenced or suspended at any time without notice. We have not yet repurchased any bonds under the bond repurchase program.

Corporate Organization

Berry Corp., as Berry LLC's parent company, has no independent assets or operations. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. Berry Corp. and Berry LLC currently do not have any other subsidiaries. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than under the RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

The RBL Facility permits Berry LLC to make distributions to Berry Corp. so long as both before and after giving pro forma effect to such distribution no default or borrowing base deficiency exists, availability equals or exceeds 15% of the then effective borrowing base, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.75 to 1.00. The conditions are currently met with significant margin.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Three Months Ended March 31,	
	2020	**2019**
	(in thousands)	
Net cash:		
Provided by operating activities	$ 44,483	$ 21,097
Used in investing activities	(43,038)	(52,791)
Used in financing activities	(1,444)	(35,324)
Net increase (decrease) in cash and cash equivalents	$ 1	$ (67,018)

Operating Activities

Cash provided by operating activities increased for the three months ended March 31, 2020 by approximately $23 million when compared to the three months ended March 31, 2019, due to increased derivatives settlements received of $5 million, decreased taxes, other than income taxes, of $4 million, decreased leases operating expenses and electricity generation expenses of $11 million and working capital improvements of $20 million. These increases were partially offset by decreased sales of $13 million and increased general and administrative expenses of $4 million.

Investing Activities

The following provides a comparative summary of cash flows from investing activities:

	Three Months Ended March 31,	
	2020	**2019**
	(in thousands)	
Capital expenditures:(1)		
Development of oil and natural gas properties	$ (45,542)	$ (47,679)
Purchase of other property and equipment	(1,227)	(1,419)
Changes in capital investment accruals	3,533	(3,693)
Other	198	—
Cash used in investing activities	$ (43,038)	$ (52,791)

(1) Based on actual cash payments rather than accruals.

Cash used in investing activities decreased $10 million for the three months ended March 31, 2020 when compared to the same period in 2019, primarily due to a decrease in capital spending in accordance with the 2020 capital budget.

Financing Activities

Cash used by financing activities was approximately $1 million for the three months ended March 31, 2020 and decreased by approximately $34 million from the three months ended March 31, 2019. The decrease is largely due to treasury stock purchases of $25 million in the three months ended March 31, 2019 and none in the three months ended March 31, 2020. Additionally, we borrowed approximately $9 million more on the RBL Facility in 2020 for working capital needs.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2019 to March 31, 2020 are discussed below.

	March 31, 2020	December 31, 2019
	(in thousands)	
Cash and cash equivalents	$ 1	$ —
Accounts receivable, net	$ 48,602	$ 71,867
Derivative instruments assets - current and long-term	$ 185,104	$ 9,691
Other current assets	$ 19,730	$ 19,399
Property, plant & equipment, net	$ 1,295,613	$ 1,576,267
Other non-current assets	$ 10,480	$ 12,974
Accounts payable and accrued liabilities	$ 108,720	$ 151,811
Derivative instruments liabilities - current and long-term	$ 283	$ 4,958
Long-term debt	$ 403,663	$ 394,319
Deferred income taxes liability - long-term	$ 35,404	$ 9,057
Asset retirement obligation (long-term)	$ 134,877	$ 124,019
Other non-current liabilities	$ 26,757	$ 33,586
Equity	$ 849,826	$ 972,448

See “—Liquidity and Capital Resources” for discussions about the changes in cash and cash equivalents.

The $23 million decrease in accounts receivable was driven mostly by lower sales period-over-period, partially offset by higher hedge settlements outstanding at each period-end.

The $171 million increase in derivative assets and liabilities reflected the appreciation in the mark-to-market values relative to the strike price of the derivatives at the end of each period presented, as well as the change in positions held at the end of each period and the settlements received and paid throughout the periods.

The $281 million decrease in property, plant and equipment was largely the result of the $289 million impairment on our oil and gas properties as well as depreciation expense, partially offset by capital investments.

The $2 million decrease in other non-current assets includes debt issuance amortization and impairment of oil and gas assets.

The $43 million decrease in accounts payable and accrued liabilities included approximately $15 million for royalties paid in the first quarter, $10 million for decreased accruals for various capital and operating costs due to the reduced level of these costs at the end of each period, $12 million reclassified from current to long-term portion of the asset retirement obligation based on budgeted spend and minimum state requirements, and $7 million for interest for scheduled interest payments made in the first quarter 2020.

The $9 million increase in long-term debt primarily represented borrowing and repayment activity from our RBL Facility for monthly working capital fluctuations.

The $26 million increase in long-term deferred income taxes liability is due to the income tax expense incurred during the period.

The increase in the long-term portion of the asset retirement obligation increased from $124 million at December 31, 2019 to $135 million at March 31, 2020 due to $2 million of accretion and reclassification of $12 million from the current portion due to changes in budgeted spending and minimum state requirements. These increases were partially offset by $3 million of liabilities settled during the period.

The decrease in other non-current liabilities was driven by the impact from lower allowance spot prices resulting in lower greenhouse gas liability of $7 million for the three months ended March 31, 2020, which is due for payment more than one year from March 31, 2020.

The decrease in equity of $123 million was due to net loss of $115 million and $10 million of common stock dividends declared. These decreases were partially offset by $2 million of stock-based incentive equity awards, net of taxes.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiary, are subject to lawsuits, environmental and other claims and other contingencies that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at March 31, 2020 and December 31, 2019. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiary, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with transactions that they have entered into with us. As of March 31, 2020, we are not aware of material indemnity claims pending or threatened against us.

We have certain commitments under contracts, including purchase commitments for goods and services. We previously had an obligation to a counterparty in connection with our Piceance assets to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. The counterparty has since filed a claim challenging the sufficiency of such access which we dispute. We intend to defend the matter vigorously, however, given the uncertainty of litigation and the preliminary stage of the case, among other things, at this time we cannot estimate the reasonable possible loss, if any, that may result from this action.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of March 31, 2020:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Debt obligations:					
RBL Facility	$ 10,950	$ —	$ 10,950	$ —	$ —
2026 Notes	400,000	—	—	—	400,000
Interest[1]	164,529	28,000	56,000	56,000	24,529
Other:					
Asset retirement obligations[2]	148,577	13,700	—	—	134,877
Off-Balance Sheet arrangements:					
Processing and transportation contracts[3]	11,878	5,994	5,201	683	—
Operating lease obligations	11,207	1,393	3,476	2,986	3,352
Other[4]	6,000	6,000	—	—	—
Total contractual obligations	$ 753,141	$ 55,087	$ 75,627	$ 59,669	$ 562,758

(1) Represents interest on the 2026 Notes computed at 7.0% through contractual maturity in 2026.

(2) Represents the estimated future asset retirement obligations on a discounted basis. We do not show the long-term asset retirement obligations by year as we are not able to precisely predict the timing of these amounts. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to revisions based on numerous factors, including the rate of inflation, changing technology, and changes to federal, state and local laws and regulations. See Note 6 for additional information.

(3) Amounts include payments which will become due under long-term agreements to purchase goods and services used in the normal course of business to secure transportation of our natural gas production to market as well as pipeline and processing capacity.

(4) We have certain commitments under contracts, including purchase commitments for goods and services. We previously had an obligation to a counterparty in connection with our Piceance assets to either build a road or secure a license for alternative access, in lieu of paying a $6 million penalty. As of March 31, 2020, we fulfilled the obligation by delivering the access license pursuant to the agreement. The counterparty has since filed a claim challenging the sufficiency of such access which we dispute. We intend to defend the matter vigorously, however, given the uncertainty of litigation and the preliminary stage of the case, among other things, at this time we cannot estimate the reasonable possible loss, if any, that may result from this action.

Critical Accounting Policies and Estimates

See Note 1, Basis of Presentation, in the Notes to Consolidated Condensed Financial Statements in Part I, Item 1 of this Form 10-Q.

Cautionary Note Regarding Forward-Looking Statements

The information included or incorporated by reference in this Quarterly Report includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, capital for sustained production levels, expected production and costs, reserves, hedging activities, capital expenditures, return of capital, improvement of recovery factors and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect us are discussed below in Part II, Item 1A. “Risk Factors” in this Quarterly Report, as well as in Part I, Item 1A. "Risk Factors" our most recent Annual Report on Form 10-K and other filings with the Securities and Exchange Commission.

Factors (but not all the factors) that could cause results to differ include among others:

- the length, scope and severity of the recent COVID-19 pandemic, including the effects of related public health concerns and the impact of actions taken by governmental authorities and other third parties in response to the pandemic and its impact on commodity prices, supply and demand considerations, and storage capacity;
- global economic trends, geopolitical risks and general economic and industry conditions, such as those resulting from the COVID-19 pandemic and from the actions of OPEC+, including the escalation of tensions between Saudi Arabia and Russia and changes in OPEC+'s production levels;
- volatility of oil, natural gas and NGL prices, including the sharp decline in crude oil prices that occurred in the first quarter and continued into the second quarter of 2020;
- supply of and demand for oil, natural gas and NGLs;
- disruptions to, capacity constraints in, or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures, meet our working capital requirements or fund planned investments;
- price fluctuations and availability of natural gas and electricity and the cost of steam;
- our ability to use derivative instruments to manage commodity price risk;
- the regulatory environment, including availability or timing of, and conditions imposed on, obtaining and/or maintaining permits and approvals, including those necessary for drilling and/or development projects;
- our ability to meet our planned drilling schedule, including due to our ability to obtain permits on a timely basis or at all, and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- the impact of current, pending and/or future laws and regulations, and of legislative and regulatory changes and other government activities, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- the California and global energy future, including the factors and trends that are expected to shape it, such as concerns about climate change and other air quality issues, the transition to a low-emission economy and the expected role of different energy sources;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- drilling and production results, including lower–than–expected production, reserves or resources from development projects or higher–than–expected decline rates;
- our ability to obtain timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells;

- changes in tax laws;
- effects of competition;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- the creditworthiness and performance of our counterparties with respect to our hedges;
- impact of derivatives legislation affecting our ability to hedge;
- failure of risk management and ineffectiveness of internal controls;
- catastrophic events, including wildfires, earthquakes and pandemics;
- environmental risks and liabilities under federal, state, tribal and local laws and regulations (including remedial actions);
- potential liability resulting from pending or future litigation;
- our ability to recruit and/or retain key members of our senior management and key technical employees;
- information technology failures or cyber attacks; and
- governmental actions and political conditions, as well as the actions by other third parties that are beyond our control.

Except as required by law, we undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

All forward-looking statements, expressed or implied, included in this prospectus are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three months ended March 31, 2020, there were no material changes in the information required to be provided under Item 305 of Regulation S-K included under the caption *Management's Discussion and Analysis of Financial Condition and Results of Operations (Incorporating Item 7A)-Quantitative and Qualitative Disclosures About Market Risk,* in the 2019 Annual Report, except as discussed below.

Price Risk

Our most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues, certain costs such as fuel gas, and cash flows are likewise affected. Additional non-cash impairment charges for our oil and gas properties may be required if commodity prices experience further significant declines.

We have hedged a large portion of our expected crude oil production and our natural gas purchase requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls and puts to hedge. We do not enter into derivative contracts for speculative trading purposes and we have not accounted for our derivatives as cash-flow or fair-value hedges. We continuously consider the level of our oil production and gas purchases that is appropriate to hedge based on a variety of factors, including, among other things, current and future expected commodity prices, our expected capital and operating costs, our overall risk profile, including leverage, size and scale, as well as any requirements for, or restrictions on, levels of hedging contained in any credit facility or other debt instrument applicable at the time.

We determine the fair value of our oil and natural gas derivatives using valuation techniques which utilize market quotes and pricing analysis. Inputs include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate data provided by third parties by understanding the valuation inputs used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. At March 31, 2020, the fair value of our hedge positions was a net asset of approximately $185 million. A 10% increase in the oil and natural gas index prices above the March 31, 2020 prices would result in a decrease in the net asset to approximately $171 million; conversely, a 10% decrease in the oil and natural gas index prices below the March 31, 2020 prices would result in an increase in the net asset to approximately $233 million. For additional information about derivative activity, see Note 3.

Actual gains or losses recognized related to our derivative contracts depend exclusively on the price of the underlying commodities on the specified settlement dates provided by the derivative contracts.

Credit Risk

Our credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We actively manage this credit risk by selecting counterparties that we believe to be financially strong and continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

As of March 31, 2020, the substantial majority of the credit exposure related to our derivative financial instruments was with investment grade counterparties. We believe exposure to credit-related losses at March 31, 2020 was not material and actual losses associated with credit risk have not been material for all periods presented.

Interest Rate Risk

Our RBL Facility has a variable interest rate on outstanding balances. As of March 31, 2020, we had approximately $11 million in borrowings under our RBL Facility and thus the interest rate risk exposure is not material. The 2026 Notes have a fixed interest rate and thus we are not exposed to interest rate risk on these instruments. See Note 2 to our consolidated financial statements for additional information regarding interest rates on our outstanding debt.

Item 4. Controls and Procedures

Our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer supervised and participated in our evaluation 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 of the end of the period covered by this report. Based upon that evaluation, they each concluded that our disclosure controls and procedures were effective as of March 31, 2020.

There were no changes in the Company’s internal control over financial reporting during the first quarter of 2020 that materially affected, or were reasonably likely to materially affect, the Company’s internal control over financial reporting.

Part II – Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 4 to the condensed consolidated financial statements in Part I of this Form 10-Q and Note 5 to our consolidated financial statements for the year ended December 31, 2019 included in the Annual Report.

Item 1A. Risk Factors

In addition to factors noted in our most recent Annual Report, additional factors that may curtail, delay or cancel our scheduled drilling projects and ongoing operations, include the following:

The COVID-19 pandemic has adversely affected our business, and the ultimate effect on our operations and financial condition will depend on future developments, which are highly uncertain and cannot be predicted.

In early 2020, global health care systems and economies began to experience strain from the spread of COVID-19. This pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, there has been a significant reduction in demand for and prices of crude oil, natural gas and NGL, which was compounded by the announcement by Saudi Arabia of a significant increase in its maximum crude oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of OPEC+ would expire on April 1, 2020, and the ensuing expiration thereof.

In mid-April 2020, members of OPEC+ agreed to certain production cuts; however, these cuts have yet to offset the significant decrease in demand resulting from the COVID-19 pandemic and related economic repercussions. As of May 1, 2020, the benchmark Brent oil price was $26.44 per barrel as compared to the average benchmark Brent oil price was $63.15 per barrel used to determine our 2019 year end reserves based on SEC pricing. The current futures forward curve for Brent crude indicates that prices may continue at extremely low levels for an extended time. Additionally, although the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. Even as Brent pricing has fallen due to demand destruction caused by the COVID-19 pandemic coupled with the OPEC+ supply surge, we have recently experienced an adverse widening in the price differential between Brent and the California benchmark due to the lack of local demand and storage capacity. If California pricing remains weak, or declines further, our financial and operating results will be adversely affected.

If the reduced demand for and prices of crude oil and NGLs continue for a prolonged period, our operations, financial condition, cash flows, level of expenditures and the quantity of estimated proved reserves that may be attributed to our properties may be materially and adversely affected. At the end of March 2020, the Company reduced its planned capital expenditures by more than 50% to $65 million, which may negatively impact the Company’s production levels in future quarters due to the natural production decline of its assets until such time as it is able to resume drilling, which combined with expected lower commodity prices would materially adversely affect our cash flows and may materially and adversely affect the quantity of estimated proved reserves that may be attributed to our properties or cause the Company to take an additional impairment. A persistent price decline could adversely affect the economics of our existing wells and planned future wells, possibly result in additional impairment charges to existing properties and cause us to delay or abandon planned drilling operations as uneconomical.

Our operations also may be adversely affected if significant portions of our workforce- and that of our customers and suppliers - are unable to work effectively, including because of illness, quarantines, government actions, or other restrictions in connection with the pandemic. Over the later part of March, we implemented workplace restrictions in response to developing government directives and we are continuing to monitor national, state and local government directives where we have operations and/or offices. For the last several weeks, most of our personnel have been working remotely and many of our key vendors, service suppliers and partners have been as well. As a result of such remote work arrangements, certain operational and other processes could slow which may result in longer time to execute critical business functions, higher operating costs and uncertainties regarding the quality of services and supplies, any of which could adversely affect our operating results for as long as the current pandemic persists and potentially for some time after the pandemic subsides.

The extent to which the COVID-19 pandemic adversely affects our business, results of operations, and financial condition will depend on future developments, which are highly uncertain and cannot be predicted, including the scope and duration of the pandemic and actions taken by governmental authorities and other third parties in response to the pandemic.

Our ability to operate profitably and our financial condition are highly dependent on energy prices. The outbreak of COVID-19 followed by certain actions taken by OPEC + caused crude oil prices to decline significantly in the first quarter of 2020, and that deterioration has continued into the second quarter. If oil prices continue to decline or remain at current levels for a prolonged period, our business, financial condition and results of operations may be materially and adversely affected.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been extremely volatile and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas, including changes in demand resulting from general and specific economic conditions relating to the business cycle and other factors (e.g., global health epidemics such as the recent COVID-19 pandemic);
- the actions of OPEC / OPEC+;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Global economic growth drives demand for energy from all sources, including fossil fuels. Should the U.S. and global economies experience weakness, demand for energy may decline. Similarly, should growth in global energy production outstrip demand, excess supplies may arise. Declines in demand and excess supplies may result in accompanying declines in commodity prices and deterioration of our financial position along with our ability to operate profitably and our ability to obtain financing to support operations.

In the first quarter of 2020, crude oil prices fell sharply and dramatically, due in part to significantly decreased demand as a result of the COVID-19 pandemic and the announcement by Saudi Arabia of a significant increase in its maximum crude oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of OPEC+ would expire on April 1, 2020, and the ensuing expiration thereof. On April 12, 2020, members of OPEC+ agreed to certain production cuts; however, these cuts have yet to offset the significant decrease in demand resulting from the COVID-19 pandemic and related economic repercussions, and oil prices have remained at historical low levels for the second quarter. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. Moreover, even as Brent pricing has fallen due to demand destruction caused by the COVID-19 pandemic coupled with the OPEC+ supply surge, we have also experienced a widening in the price differential between Brent pricing and the California benchmark pricing, caused primarily by the lack of local demand and storage capacity. If California pricing remains weak, or declines further, our financial and operating results will be adversely affected.

Additionally, the sudden and extreme supply demand in-balance has also resulted in a lack of storage capacity, and if storage availability does not increase in the near term Brent and/or California oil prices may go materially lower and could potentially even become negative as WTI oil prices did on April 20, 2020. If crude oil prices continue to decline or remain at current levels for a prolonged period, our operations, financial condition, cash flows, level of expenditures and the quantity of estimated proved reserves that may be attributed to our properties may be materially and adversely affected.

Past declines in prices reduced, and any declines that may occur in the future can be expected to reduce, our revenues and profitability as well as the value of our reserves. Such declines adversely affect well and reserve economics and may reduce the amount of oil and natural gas that we can produce economically, resulting in deferral or cancellation of planned drilling and related activities until such time, if ever, as economic conditions improve sufficiently to support such operations. Any extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

The marketability of our production is dependent upon transportation and storage facilities and other facilities, most of which we do not control, and the availability of such transportation and storage capabilities, which have been severely limited by recent market conditions related to the COVID-19 pandemic and the current oversupply of oil and natural gas. If additional facilities do not become available, or, even if such facilities are available, but we are unable to access such facilities on commercially reasonable terms, our operations will likely be interrupted, our production could be curtailed, and our revenues reduced, among other consequences.

The marketing of oil, natural gas and NGLs production depends in large part on the availability, proximity and capacity of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities, as well as the existence of adequate markets. Because of the significantly reduced demand for oil and natural gas as a result of the COVID-19 pandemic and the current oversupply of oil and natural gas in the market, available storage and transportation capacity for our production is very limited and may become completely unavailable in the near future. Storage has become increasingly scarce due to the unprecedented dual impact of a severe global oil demand decline coupled with a substantial increase in supply. As traditional tanks have filled, large quantities of oil are being stored in offshore tankers around the world, including off the coast of California. Where storage is available, such as offshore tankers, storage costs have increased sharply. If the imbalance between supply and demand and the related shortage of storage capacity do not improve, the prices we receive for our production will likely continue to deteriorate and could potentially even become negative as WTI oil prices did on April 20, 2020.

Based on our current storage commitments, and assuming we are unable to obtain additional storage in the near term, beginning in the second quarter of 2020, we could be forced to shut-in a significant amount of our California production, as well as curtail some of our Utah and Colorado production, which could have a material, adverse effect on our financial condition, liquidity and operational results. Whether and when we will have to reduce or shut-in production, and the extent and duration to which we may have to do so, cannot be reasonably predicted at this time. If we are forced to shut in production, we will incur additional costs to bring the associated wells back online. While production is shut in, we will likely incur additional costs and operating expenses to, among other things, maintain the health of the reservoirs, meet contractual obligations and protect our interests, but without the associated revenue. Additionally, depending on the duration of the shut-in, and whether we have also shut-in steam injection for the associated reservoirs rather than incur those costs, the wells may not, initially or at all, come back online at similar rates to those at the time of shut-in. Depending on the duration of the steam injection shut-in time, and the resulting inefficiency and economics of restoring the reservoir to its energetic and heated state, our proved reserve estimates could be decreased and there could be potential impairments and associated charges to our earnings. A reduction in our reserves could also result in a reduction to our borrowing base under the RBL Facility and our liquidity. The ultimate significance of the impact of any production disruptions, including the extent of the adverse impact on our financial and operational results, will be dictated by the length of time that such disruptions continue which will, in turn, depend on the how long storage remains filled and unavailable to us, which is largely based on the lack of demand for our products due to the impact of the COVID-19 impact, the duration of which is currently unknowable.

In addition to the constraints we are facing due to storage capacity shortages, the volume of oil and natural gas that we can produce is subject to limitations resulting from pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, and physical damage to the gathering, transportation, storage, processing, fractionation, refining or export facilities that we utilize. The curtailments arising from these and similar circumstances may last from a few days to several months or longer and, in many cases, we may be provided only limited, if any, advance notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or any inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

We may not be able to use a portion of our net operating loss carryforwards and other tax attributes to reduce our future U.S. federal and state income tax obligations, which could adversely affect our net income and cash flows.

We currently have substantial U.S. federal and state net operating loss ("NOL") carryforwards and U.S. federal general business credits of approximately (subject to change each quarter; as of December 31, 2019 estimated U.S. federal and state net operating loss ("NOL") carryforwards of approximately $121.8 million and $42.1 million, respectively, and U.S. federal general business credits of approximately $47.6 million). Our ability to use these tax attributes to reduce our future U.S. federal and state income tax obligations depends on many factors, including our future taxable income, which cannot be assured. In addition, our ability to use NOL carryforwards and other tax attributes may be subject to significant limitations under Section 382 and Section 383 of the Internal Revenue Code of 1986, as amended (the "Code"). Under those sections of the Code, if a corporation undergoes an "ownership change" (as defined in Section 382 of the Code), the corporation's ability to use its pre-change NOL carryforwards and other tax attributes may be substantially limited.

Determining the limitations under Section 382 of the Code is technical and highly complex. A corporation generally will experience an ownership change if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of the corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. We may in the future undergo an ownership change under Section 382 of the Code. If an ownership change occurs, our ability to use our NOL carryforwards and other tax attributes to reduce our future U.S. federal and state income tax obligations may be materially limited, which could adversely affect our net income and cash flows.

The payment of dividends will be at the discretion of our Board of Directors.

While we have regularly declared a quarterly dividend since our July IPO, including a dividend of $0.12 per share for the first quarter of 2020, the payment and amount of future dividend payments, if any, are subject to declaration by our Board of Directors. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our operating expenses and other factors our board of directors deems relevant. Additionally, covenants contained in our RBL Facility and the indentures governing our 2026 Notes could limit the payment of dividends. In April 2020, in response to the unprecedented impact on our business from the significant decline in oil prices and the COVID-19 pandemic, we temporarily suspended our quarterly dividend until oil prices recover. We are under no obligation to make dividend payments on our common stock and cannot be certain when such payments may resume in the future.

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

Stock Repurchase Program

In December 2018, our Board of Directors adopted a program for the opportunistic repurchase of up to $100 million of our common stock. Based on the Board's evaluation of market conditions for our common stock at that time, they authorized initial repurchases of up to $50 million under the program. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. We are not required or otherwise obligated to repurchase any additional shares any repurchases may be commenced or suspended at any time without notice. Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and does not obligate Berry Corp. to purchase shares during any period or at all. Any shares acquired will be available for general corporate purposes.

The Company has repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million as of December 31, 2019. For the three months ended March 31, 2020, we did not repurchase any shares under the stock repurchase program.

Item 6. Exhibits

Exhibit Number	Description
3.1	Second Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 of Form 8-K filed February 19, 2020)
3.2	Third Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.2 of Form 8-K filed February 19, 2020)
3.3	Certificate of Designation of Series A Convertible Preferred Stock of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.4 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.4	Certificate of Amendment to Certificate of Designation (incorporated by reference to Exhibit 3.1 of Form 8-K filed July 30, 2018)
10.1	Second Amended and Restated Employment Agreement by and between Berry Petroleum Company, LLC and Cary D. Baetz, effective March 1, 2020 (incorporated by reference to Exhibit 10.1 of Form 8-K filed March 30, 2020)
10.2	Second Amended and Restated Employment Agreement by and between Berry Petroleum Company, LLC and Gary A. Grove, effective March 1, 2020 (incorporated by reference to Exhibit 10.1 of Form 8-K filed March 30, 2020)
31.1*	Section 302 Certification of Chief Executive Officer
31.2*	Section 302 Certification of Chief Financial Officer
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer
99.1	Berry Corporation (bry) Code of Business Conduct and Ethics (incorporated by reference to Exhibit 99.1 of Form 8-K filed March 30, 2020)
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

GLOSSARY OF COMMONLY USED TERMS

The following are abbreviations and definitions of certain terms that may be used in this report, which are commonly used in the oil and natural gas industry:

"*Absolute TSR*" means absolute total stockholder return.

"*AROs*" means asset retirement obligations.

"*Adjusted EBITDA*" is a non-GAAP financial measure defined as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including gains and losses on sale of assets, restructuring costs and reorganization items.

"*Adjusted G&A*" or "*Adjusted General and Administrative Expenses*" is a non-GAAP financial measure defined as general and administrative expenses adjusted for restructuring and other non-recurring costs and non-cash stock compensation expense.

"*Adjusted Net Income (Loss)*" is a non-GAAP financial measure defined as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate.

"*API*" gravity means the relative density, expressed in degrees, of petroleum liquids based on a specific gravity scale developed by the American Petroleum Institute.

"*basin*" means a large area with a relatively thick accumulation of sedimentary rocks.

"*Bbl*" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"*Bcf*" means one billion cubic feet, which is a unit of measurement of volume for natural gas.

"*BLM*" means for the U.S. Bureau of Land Management.

"*Boe*" means barrel of oil equivalent, determined using the ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas.

"*Boe/d*" means Boe per day.

"*Break even*" means the Brent price at which we expect to generate positive Levered Free Cash Flow.

"*Brent*" means the reference price paid in U.S. dollars for a barrel of light sweet crude oil produced from the Brent field in the UK sector of the North Sea.

"*Btu*" means one British thermal unit—a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"*CAA*" is an abbreviation for the Clean Air Act, which governs air emissions.

"*CalGEM*" is an abbreviation for the California Geologic Energy Management Division.

"*Cap-and-trade*" is a statewide program in California established by the Global Warming Solutions Act of 2006 which outlined an enforceable compliance obligation beginning with 2013 GHG emissions and currently extended through 2030.

"*CARB*" is an abbreviation for the California Air Resources Board.

"*CCA*" or "*CCAs*" is an abbreviation for California carbon allowances.

"*CERCLA*" is an abbreviation for the Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous substances have been released into the environment (commonly known as "*Superfund*").

"*Clean Water Rule*" refers to the rule issued in August 2015 by the EPA and U.S. Army Corps of Engineers which expanded the scope of the federal jurisdiction over wetlands and other types of waters.

"*COGCC*" is an abbreviation for the Colorado Oil and Gas Conservation Commission.

"*Completion*" means the installation of permanent equipment for the production of oil or natural gas.

"*Condensate*" means a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"*CPUC*" is an abbreviation for the California Public Utilities Commission.

"*CWA*" is an abbreviation for the Clean Water Act, which governs discharges to and excavations within the waters of the United States.

"*DD&A*" means depreciation, depletion & amortization.

"*Development drilling*" or "*Development well*" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"*Diatomite*" means a sedimentary rock composed primarily of siliceous, diatom shells.

"*Differential*" means an adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

"*Downspacing*" means additional wells drilled between known producing wells to better develop the reservoir.

"EH&S" is an abbreviation for Environmental, Health & Safety.

"*Enhanced oil recovery*" means a technique for increasing the amount of oil that can be extracted from a field.

"*EOR*" means enhanced oil recovery.

"*EPA*" is an abbreviation for the United States Environmental Protection Agency.

"*EPS*" is an abbreviation for earnings per share.

"*ESA*" is an abbreviation for the federal Endangered Species Act.

"*Exploration activities*" means the initial phase of oil and natural gas operations that includes the generation of a prospect or play and the drilling of an exploration well.

"*FASB*" is an abbreviation for the Financial Accounting Standards Board.

"*FERC*" is an abbreviation for the Federal Energy Regulatory Commission.

"*Field*" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

"*FIP*" is an abbreviation for Federal Implementation Plan.

"*Formation*" means a layer of rock which has distinct characteristics that differ from those of nearby rock.

"*Fracturing*" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks by connecting pores together.

"*GAAP*" is an abbreviation for U.S. generally accepted accounting principles.

"*Gas*" or "*Natural gas*" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"*GHG*" or "*GHGs*" is an abbreviation for greenhouse gases.

"*Gross Acres*" or "*Gross Wells*" means the total acres or wells, as the case may be, in which we have a working interest.

"*Held by production*" means acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.

"*Henry Hub*" is a distribution hub on the natural gas pipeline system in Erath, Louisiana.

"*Hydraulic fracturing*" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability.

"*Horizontal drilling*" means a wellbore that is drilled laterally.

"*ICE*" means Intercontinental Exchange.

"*Infill drilling*" means drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.

"*Injection Well*" means a well in which water, gas or steam is injected, the primary objective typically being to maintain reservoir pressure and/or improve hydrocarbon recovery.

"*IOR*" means improved oil recovery.

"*IPO*" is an abbreviation for initial public offering.

"*LCFS*" is an abbreviation for low carbon fuel standard.

"*Leases*" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"*Levered Free Cash Flow*" is a non-GAAP financial measure defined as Adjusted EBITDA less interest expense, dividends and capital expenditures.

"*LIBOR*" is an abbreviation for London Interbank Offered Rate.

"*MBbl*" means one thousand barrels of oil, condensate or NGLs.

"*MBbl/d*" means MBbl per day.

"*MBoe*" means one thousand barrels of oil equivalent.

"*MBoe/d*" means MBoe per day.

"*Mcf*" means one thousand cubic feet, which is a unit of measurement of volume for natural gas.

"*MMBbl*" means one million barrels of oil, condensate or NGLs.

"*MMBoe*" means one million barrels of oil equivalent.

"*MMBtu*" means one million Btus.

"*MMcf*" means one million cubic feet, which is a unit of measurement of volume for natural gas.

"*MMcf/d*" means MMcf per day.

"*MTBA*" is an abbreviation for Migratory Bird Treaty Act.

"*MW*" means megawatt.

"*MWHs*"means megawatt hours.

"*NAAQS*" is an abbreviation for the National Ambient Air Quality Standard.

"*NASDAQ*" means Nasdaq Global Select Market.

"*NEPA*" is an abbreviation for the National Environmental Policy Act, which requires careful evaluation of the environmental impacts of oil and natural gas production activities on federal lands.

"*Net Acres*" or "*Net Wells*" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"*Net revenue interest*" means all of the working interests, less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"*NGA*" is an abbreviation for the Natural Gas Act.

"*NGL*" or "*NGLs*" means natural gas liquids, which are the hydrocarbon liquids contained within natural gas.

"*NRI*" is an abbreviation for net revenue interest.

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

“*Operator*” means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

“*OSHA*” is an abbreviation for the Occupational Safety and Health Act of 1970.

“*OTC*” means over-the-counter

“*PALs*” is an abbreviation for project approval letters.

“*PCAOB*” is an abbreviation for the Public Company Accounting Oversight Board.

“*PDNP*” is an abbreviation for proved developed non-producing.

“*PDP*” is an abbreviation for proved developed producing.

“*Permeability*” means the ability, or measurement of a rock’s ability, to transmit fluids.

“*PHMSA*” is an abbreviation for the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration.

“*Play*” means a regionally distributed oil and natural gas accumulation. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations.

“*PPA*” is an abbreviation for power purchase agreement.

“*Production costs*” means costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC’s Regulation S-X, Rule 4-10(a)(20).

“*Productive well*” means a well that is producing oil, natural gas or NGLs or that is capable of production.

“*Proppant*” means sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.

“*Prospect*” means a specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

“*Proved developed reserves*” means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“*Proved developed producing reserves*” means reserves that are being recovered through existing wells with existing equipment and operating methods.

“*Proved reserves*” means the estimated quantities of oil, gas and gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"*Proved undeveloped drilling location*" means a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*" means proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"*PSUs*" means performance-based restricted stock units

"*PURPA*" is an abbreviation for the Public Utility Regulatory Policies Act.

"*PV-10*" is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC-prescribed pricing assumptions for the period. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the company on a comparative basis to other companies and from period to period.

"*QF*" means qualifying facility.

"*RCRA*" is an abbreviation for the Resource Conservation and Recovery Act, which governs the management of solid waste.

"*Realized price*" means the cash market price less all expected quality, transportation and demand adjustments.

"*Reasonable certainty*" means a high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

"*Recompletion*" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

"*Relative TSR*" means relative total stockholder return.

"*Reserves*" means estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

"*Reservoir*" means a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"*Resources*" means quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

"*Royalty*" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"*Royalty interest*" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"*RSUs*" is an abbreviation for restricted stock units.

"SARs" is an abbreviation for stock appreciation rights.

"*SDWA*" is an abbreviation for the Safe Drinking Water Act, which governs the underground injection and disposal of wastewater;.

"*SEC Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules based on the unweighted arithmetic average of oil and natural gas prices as of the first day of each of the 12 months ended on the given date.

"*Seismic Data*" means data produced by an exploration method of sending energy waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

"*Spacing*" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*SPCC plans*" means spill prevention, control and countermeasure plans.

"*Steamflood*" means cyclic or continuous steam injection.

"*Standardized measure*" means discounted future net cash flows estimated by applying year-end prices to the estimated future production of proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Stimulating*" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks by connecting pores together.

"*Strip Pricing*" means pricing calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules with the exception of pricing that is based on average annual forward-month ICE (Brent) oil and NYMEX Henry Hub natural gas contract pricing in effect on a given date to reflect the market expectations as of that date.

"*Superfund*" is a commonly known term for CERLA.

"*UIC*" is an abbreviation for the Underground Injection Control program.

"*Undeveloped acreage*" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

“*Unit*” means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“*Unproved reserves*” means reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

“*Wellbore*” means the hole drilled by the bit that is equipped for natural resource production on a completed well. Also called well or borehole.

“*Working interest*” means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner’s royalty, any overriding royalties, production costs, taxes and other costs.

“*Workover*” means maintenance on a producing well to restore or increase production.

“*WST*” is an abbreviation for well stimulation treatment.

“*WTI*” means West Texas Intermediate.

SIGNATURES

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

		Berry Corporation (bry) (Registrant)
Date:	May 7, 2020	*/s/* Cary Baetz
		Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	May 7, 2020	*/s/* M. S. Helm
		Michael S. Helm Chief Accounting Officer (Principal Accounting Officer)

EXHIBIT 31.1

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, A. T. “Trem” Smith, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Berry Corporation (bry) (the “registrant”);

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 this 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 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 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 registrant's board of directors (or persons performing the equivalent function):

   (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.

Date: May 7, 2020

/s/ A. T. Smith

A. T. "Trem" Smith

President and Chief Executive Officer

EXHIBIT 31.2

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cary Baetz, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Berry Corporation (bry) (the "registrant");

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 this 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 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 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 registrant’s board of directors (or persons performing the equivalent function):

   (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.

Date: May 7, 2020

/s/ Cary Baetz

Cary Baetz

Executive Vice President and
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO PURSUANT TO
18 U.S.C. § 1350,
AS ADOPTED PURSUANT TO
§ 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report on Form 10-Q of Berry Corporation (bry) (the "Company") for the fiscal period ended March 31, 2020, as filed with the Securities and Exchange Commission on May 7, 2020 (the "Report"), A. T. "Trem" Smith, as Chief Executive Officer of the Company, and Cary Baetz, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section § 1350, as adopted pursuant to Section § 906 of the Sarbanes-Oxley Act of 2002, to the best of our knowledge that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	May 7, 2020	/s/ A. T. Smith
		A. T. "Trem" Smith
		President and Chief Executive Officer

Date:	May 7, 2020	/s/ Cary Baetz
		Cary Baetz
		Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Berry Corporation (bry) and will be retained by Berry Corporation (bry) and furnished to the Securities and Exchange Commission or its staff upon request.

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.