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 September 30, 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 October 31, 2020 79,929,335

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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)

	September 30, 2020	December 31, 2019
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 47,620	$ —
Accounts receivable, net of allowance for doubtful accounts of $2,215 at September 30, 2020 and $1,103 at December 31, 2019	48,798	71,867
Derivative instruments	57,658	9,166
Other current assets	20,318	19,399
Total current assets	174,394	100,432
Noncurrent assets:		
Oil and natural gas properties	1,388,544	1,675,717
Accumulated depletion and amortization	(209,956)	(209,105)
Total oil and natural gas properties, net	1,178,588	1,466,612
Other property and equipment	111,146	135,117
Accumulated depreciation	(28,979)	(25,462)
Total other property and equipment, net	82,167	109,655
Derivative instruments	2,011	525
Other noncurrent assets	9,297	12,974
Total assets	$ 1,446,457	$ 1,690,198
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 95,237	$ 151,811
Derivative instruments	337	4,817
Total current liabilities	95,574	156,628
Noncurrent liabilities:		
Long-term debt	393,219	394,319
Derivative instruments	1,179	141
Deferred income taxes	9,318	9,057
Asset retirement obligation	136,392	124,019
Other noncurrent liabilities	36,150	33,586
Commitments and Contingencies - Note 4		
Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 85,004,619 and 84,655,222 shares issued; and 79,892,373 and 79,542,976 shares outstanding, at September 30, 2020 and December 31, 2019, respectively)	85	85
Additional paid-in-capital	912,637	901,830
Treasury stock, at cost, (5,112,246 shares at September 30, 2020 and at December 31, 2019)	(49,995)	(49,995)
Retained earnings (deficit)	(88,102)	120,528
Total equity	774,625	972,448
Total liabilities and equity	$ 1,446,457	$ 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 September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 92,239	$ 141,250	$ 284,852	$ 409,259
Electricity sales	8,744	7,460	19,089	22,553
(Losses) gains on oil derivatives	(11,564)	45,509	157,398	7,546
Marketing revenues	330	413	1,075	1,657
Other revenues	0	40	53	261
Total revenues and other	89,749	194,672	462,467	441,276
Expenses and other:				
Lease operating expenses	45,243	50,957	136,727	156,765
Electricity generation expenses	4,217	3,781	11,186	14,705
Transportation expenses	1,768	2,067	5,379	5,935
Marketing expenses	326	398	1,036	1,670
General and administrative expenses	19,173	16,434	57,287	46,932
Depreciation, depletion, and amortization	35,905	27,664	108,746	75,904
Impairment of oil and gas properties	—	—	289,085	—
Taxes, other than income taxes	9,913	9,249	24,714	28,683
(Gain) losses on natural gas derivatives	(15,784)	3,008	(2,824)	10,342
Other operating expenses (income)	1,648	(550)	2,658	3,814
Total expenses and other	102,409	113,008	633,994	344,750
Other (expenses) income:				
Interest expense	(8,391)	(8,597)	(25,987)	(26,362)
Other, net	(3)	(77)	(15)	79
Total other (expenses) income	(8,394)	(8,674)	(26,002)	(26,283)
Reorganization items, net	—	(170)	—	(426)
(Loss) income before income taxes	(21,054)	72,820	(197,529)	69,817
Income tax (benefit) expense	(2,190)	20,171	1,536	19,294
Net (loss) income	$ (18,864)	$ 52,649	$ (199,065)	$ 50,523
Net (loss) income per share:				
Basic	$ (0.24)	$ 0.65	$ (2.50)	$ 0.62
Diluted	$ (0.24)	$ 0.65	$ (2.50)	$ 0.62

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

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

	Nine-Month Period Ended September 30, 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
Shares withheld for payment of taxes on equity awards and other	—	(675)	—	—	(675)
Stock based compensation	—	2,497	—	—	2,497
Purchases of treasury stock	—	—	(10,897)	—	(10,897)
Dividends declared on common stock, $0.12/share	—	—	—	(9,710)	(9,710)
Net income	—	—	—	31,972	31,972
June 30, 2019	85	897,322	(39,225)	94,134	952,316
Shares withheld for payment of taxes on equity awards and other	—	(294)	—	—	(294)
Stock based compensation	—	2,393	—	—	2,393
Dividends declared on common stock, $0.12/share	—	—	—	(9,720)	(9,720)
Net income	—	—	—	52,649	52,649
September 30, 2019	$ 85	$ 899,421	$ (39,225)	$ 137,063	$ 997,344

(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 EQUITY
(Unaudited)

	Nine-Month Period Ended September 30, 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
Shares withheld for payment of taxes on equity awards and other	—	(140)	—	—	(140)
Stock based compensation	—	4,730	—	—	4,730
Net loss	—	—	—	(64,901)	(64,901)
June 30, 2020	85	908,662	(49,995)	(69,237)	789,515
Shares withheld for payment of taxes on equity awards and other	—	(46)	—	—	(46)
Stock based compensation	—	4,021	—	—	4,021
Net loss	—	—	—	(18,864)	(18,864)
September 30, 2020	$ 85	$ 912,637	$ (49,995)	$ (88,102)	$ 774,625

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

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

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in thousands)	
Cash flows from operating activities:		
Net (loss) income	$ (199,065)	$ 50,523
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	108,746	75,904
Amortization of debt issuance costs	3,990	3,786
Impairment of oil and gas properties	289,085	—
Stock-based compensation expense	11,397	6,277
Deferred income taxes	(702)	19,294
Increase in allowance for doubtful accounts	1,112	427
Other operating expenses	2,145	4,744
Derivative activities:		
Total (gains) losses	(160,222)	2,796
Cash settlements on derivatives	106,975	26,731
Changes in assets and liabilities:		
Decrease (increase) in accounts receivable	21,985	(6,690)
Increase in other assets	(919)	(2,073)
Decrease in accounts payable and accrued expenses	(29,882)	(12,344)
Decrease in other liabilities	(10,226)	(5,108)
Net cash provided by operating activities	144,419	164,267
Cash flows from investing activities:		
Capital expenditures:		
Development of oil and natural gas properties	(58,370)	(157,281)
Purchases of other property and equipment	(3,951)	(12,394)
Changes in capital investment accruals	(10,347)	(4,613)
Acquisition of properties and equipment and other	(2,104)	(2,819)
Proceeds from sale of property and equipment and other	250	969
Net cash used in investing activities	(74,522)	(176,138)
Cash flows from financing activities:		
Borrowings under RBL credit facility	228,900	252,182
Repayments on RBL credit facility	(230,750)	(242,182)
Dividends paid on common stock	(19,447)	(29,431)
Purchase of treasury stock	—	(36,139)
Shares withheld for payment of taxes on equity awards and other	(980)	(1,239)
Net cash used in financing activities	(22,277)	(56,809)
Net increase (decrease) in cash and cash equivalents	47,620	(68,680)
Cash and cash equivalents:		
Beginning	—	68,680
Ending	$ 47,620	$ —

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

Note 1—Basis of Presentation

“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 in February 2017 and its common stock began trading on NASDAQ under the symbol "bry" in July 2018. Berry Corp. operates through its wholly-owned subsidiary, Berry LLC. Our properties are located onshore 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 Financial Accounting Standards Board ("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. During the second quarter of 2020, this adoption date was further delayed by FASB until fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. 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:

	September 30, 2020	December 31, 2019	Interest Rate	Maturity	Security
	(in thousands)				
RBL Facility	$ —	$ 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 certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	401,850			
Less: Debt Issuance Costs	(6,781)	(7,531)			
Long-Term Debt, net	$ 393,219	$ 394,319			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At September 30, 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 $8 million and $11 million net of amortization, respectively. At September 30, 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 each of the three month periods ended September 30, 2020 and September 30, 2019, the amortization expense for both the RBL Facility and 2026 Notes was approximately $1 million and was included in "interest expense" in the condensed consolidated statements of operations. For each of the nine month periods ended September 30, 2020 and September 30, 2019, the amortization expense for both the RBL Facility and 2026 Notes was approximately $4 million.

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 $314 million and $376 million at September 30, 2020 and December 31, 2019, respectively.

The RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base ("RBL Facility"). In June 2020, we completed our scheduled semi-annual borrowing base redetermination under our RBL Facility, which resulted in a decrease to the borrowing base to $200 million from $500 million; decrease to the elected commitments to $200 million from $400 million; limitation on the maximum borrowing availability under the RBL Facility to $150 million until the next semi annual borrowing base redetermination (scheduled to occur in November 2020); the implementation of certain anti-cash hoarding provisions, including the requirement to repay outstanding loans on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $30 million; and further limits dividends and share repurchases. 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.

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 September 30, 2020, our Leverage Ratio and Current Ratio were 1.5 to 1.0 and 2.7 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 September 30, 2020.

As of September 30, 2020, we had no borrowings outstanding, $7 million in letters of credit outstanding, and approximately $143 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. We have not yet repurchased any bonds under this 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 20% of the then effective borrowing base, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.5 to 1.0. 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 and gas 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 and gas sales 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 and gas sales swaps, we are the seller, so we make settlement payments for prices above the indicated weighted-average price per barrel and per MMBtu, respectively, and receive settlement payments for prices below the indicated weighted-average price per barrel and per MMBtu, respectively.

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 and gas swaps and puts to protect our sales against decreases in oil and gas prices. We also use swaps to protect our natural gas purchases against increases in 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 and gas sales hedges are classified in the revenues and other section of the statement of operations, while natural gas purchase hedges are included in expenses and other section of the statement of operations.

As of September 30, 2020, we had the following crude oil production and gas purchases hedges.

	Q4 2020	1H 2021	2H 2021
Fixed Price Oil Swaps (Brent):			
Hedged volume (MBbls)	2,208	3,438	2,084
Weighted-average price ($/Bbl)	$ 59.85	$ 45.82	$ 46.17
Purchased Oil Calls Options (Brent):			
Hedged volume (MBbls)	276	—	—
Weighted-average price ($/Bbl)	$ 65.00	$ —	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	5,060,000	9,045,000	5,535,000
Weighted-average price ($/MMBtu)	$ 2.76	$ 2.71	$ 2.73
Fixed Price Gas Purchase Swaps (SoCal Citygate):			
Hedged volume (MMBtu)	155,000	—	—
Weighted-average price ($/MMBtu)	$ 3.80	$ —	$ —

In October 2020, we added 12,500 MMBtu/d of fixed price gas sales swaps at an average price of $2.96, indexed to Northwest Pipeline Rocky Mountains and CIG, for the period January 1, 2021 through December 31, 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 September 30, 2020 and December 31, 2019:

	September 30, 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	$ 60,307	$ (2,649)	$ 57,658
Commodity Contracts	Non-current assets	2,703	(693)	2,011
Liabilities:				
Commodity Contracts	Current liabilities	(2,986)	2,649	(337)
Commodity Contracts	Non-current liabilities	(1,871)	693	(1,179)
Total derivatives		$ 58,153	$ —	$ 58,153

	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 the subject of, or party to, pending or threatened legal proceedings, contingencies and commitments involving a variety of matters that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, fines and penalties, remediation costs, 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 September 30, 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 September 30, 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. Prior to our 2017 emergence, Berry entered into a Carry and Earning Agreement with Encana, effective June 7, 2006, in connection with our Piceance assets which, among other things, required us 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. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We will 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. 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. The Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million as of December 31, 2019. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million of our $100 million repurchase program. 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. For the nine months ended September 30, 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, if at all, at the end of a three year performance period subject to both an absolute total stockholder return (“Absolute TSR”) performance metric and a relative total stockholder return (“Relative TSR”) performance metric, as further discussed and defined below. The fair value of these awards was approximately $32 million.

The RSUs awarded are solely time-based awards. The PSUs awarded include a market objective measured against both Absolute TSR and 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 PSUs 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 average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the then 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:

	September 30, 2020	December 31, 2019
	(in thousands)	
Prepaid expenses	$ 4,526	$ 4,577
Materials and supplies	11,731	10,544
Oil inventories	3,409	3,432
Other	652	846
Total other current assets	$ 20,318	$ 19,399

Other non-current assets at September 30, 2020 and December 31, 2019, included approximately $8 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:

	September 30, 2020	December 31, 2019
	(in thousands)	
Accounts payable-trade	$ 6,596	$ 13,986
Accrued expenses	45,841	57,078
Royalties payable	12,282	25,385
Taxes other than income tax liability	12,390	9,150
Accrued interest	3,500	10,500
Dividends payable	5	9,888
Asset retirement obligation - current portion	13,700	25,208
Other	923	616
Total accounts payable and accrued expenses	$ 95,237	$ 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 $136 million at September 30, 2020 was due to $7 million of accretion, $6 million of liabilities incurred and reclassification of $12 million from the current to long-term portion due to changes in anticipated spending and regulatory requirements. These increases were partially offset by $12 million of liabilities settled during the period.

Other non-current liabilities at September 30, 2020 and December 31, 2019 included approximately $35 million and $33 million of greenhouse gas liability, respectively.

Supplemental Information on the Statement of Operations

For the three months ended September 30, 2020, other operating expense was $2 million and mainly consisted of excess abandonment costs and oil tank storage fees. For three months ended September 30, 2019 other operating income was $1 million and mainly consisted of proceeds from the sale of assets, partially offset by excess abandonment costs in 2019.

For the nine months ended September 30, 2020 and 2019 other operating expenses were $3 million and $4 million, respectively. These other operating expenses mainly consist of excess abandonment costs, oil tank storage fees, and drilling rig standby charges, partially offset by tax and other refunds 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:

	Nine Months Ended September 30,	
	2020	2019
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 1,013	$ 8,474
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 29,962	$ 30,136
Income taxes	$ 222	$ —

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 for accounting purposes and have been included in "accounts payable and accrued expenses" in the condensed consolidated balance sheets, amounts are immaterial for these periods.

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 for each period presented. 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 and nine months ended September 30, 2020 no incremental RSUs or PSUs were included in the diluted EPS calculation as their effect was anti-dilutive under the “if converted” method. For the three and nine months ended September 30, 2019 we included 69,000 and 145,000 incremental RSUs in the diluted EPS calculation and no incremental PSUs were included in the EPS calculation due to their contingent nature.

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in thousands except per share amounts)			
Basic EPS calculation				
Net (loss) income	$ (18,864)	$ 52,649	$ (199,065)	$ 50,523
Weighted-average shares of common stock outstanding	79,879	80,982	79,776	81,703
Basic (loss) earnings per share	$ (0.24)	$ 0.65	$ (2.50)	$ 0.62
Diluted EPS calculation				
Net (loss) income	$ (18,864)	$ 52,649	$ (199,065)	$ 50,523
Weighted-average shares of common stock outstanding	79,879	80,982	79,776	81,703
Dilutive effect of potentially dilutive securities[1]	—	69	—	145
Weighted-average common shares outstanding - diluted	79,879	81,051	79,776	81,848
Diluted (loss) earnings per share	$ (0.24)	$ 0.65	$ (2.50)	$ 0.62

(1) No potentially dilutive securities were included in computing diluted (loss) earnings per share for the three and nine months ended September 30, 2020, 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 NGL 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 September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in thousands)			
Oil sales	$ 88,453	$ 136,710	$ 274,275	$ 392,325
Natural gas sales	3,347	4,067	9,549	14,867
Natural gas liquids sales	439	473	1,028	2,067
Electricity sales	8,744	7,460	19,089	22,553
Marketing revenues	330	413	1,075	1,657
Other revenues	—	40	53	261
Revenues from contracts with customers	101,313	149,163	305,069	433,730
(Losses) gains on oil derivatives	(11,564)	45,509	157,398	7,546
Total revenues and other	$ 89,749	$ 194,672	$ 462,467	$ 441,276

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.

As of 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 a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19 ("COVID-19") and other macroeconomic events such as the geopolitical tensions between the Organization of Petroleum Exporting Countries ("OPEC") and Russia. The COVID-19 pandemic and related economic repercussions, coupled with actions taken by OPEC and other oil producing nations ("OPEC+"), 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 futures forward curves for crude.

Consequently, we recorded a non-cash pre-tax asset impairment charge of $289 million during the first quarter of 2020 on properties in Utah and certain California locations. We evaluated 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.

We did not record an impairment charge for the second or third quarter of 2020, as there were no triggering events.

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 tax credits recorded in 2019 and other deferred tax assets would not be realized. Accordingly, we recognized a valuation allowance on our deferred tax assets for the quarter ended March 31, 2020 in the amount of $51 million. As of the quarter ended September 30, 2020, this amount is $56 million. The valuation allowance was the key contributor in the decrease in our effective tax rate from 28% for both the three and nine months ended September 30, 2019 to 10% and (1)% for the three and nine months ended September 30, 2020, respectively.

During the third quarter 2020, the Internal Revenue Service issued final regulations implementing interest expense deduction limitation rules under section 163(j) of the Internal Revenue Code. The final regulations changed certain rules on the computation and limitation of interest expense amounts and are applicable for tax years beginning on or after November 13, 2020. Early adoption is permitted for tax years beginning after December 31, 2017. We assessed the impact of these regulations being issued in the third quarter. As a result, we recognized the entirety of its $14 million of uncertain tax benefits that were recorded as of December 31, 2019. The recognition of these uncertain tax benefits did not affect the effective tax rate.

Note 11—Acquisition

In May 2020, we acquired approximately 740 net acres in the North Midway Sunset Field for approximately $5 million. We paid $2 million at closing and the remaining $3 million was paid following our first production from this property, in the fourth quarter 2020. This property is adjacent to, and extends, our existing producing area and we have identified numerous future drilling locations. We believe additional opportunities exist in other productive reservoirs of this property. We also acquired all existing idle wells on this property, some of which we plan to return to production in the near future as price and strategy dictate. We will plug and abandon the remaining idle wells pursuant to the California Idle Well Management Program. We recorded a $6 million liability for asset retirement obligations of the existing wells on this property.

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," "Berry," the "Company" or similar words in this report, we are referring to, as the context may require, (i) Berry Corporation (bry) (formerly known as Berry Petroleum Corporation, and also referred to herein as "Berry Corp.") together with its wholly owned subsidiary, Berry Petroleum, LLC (also referred to herein as "Berry LLC"), or (ii) either Berry Corp. or 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 Operations" in this report).

We have a 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 and impacting our operations, whether positive or negative, to maximize our assets, create value for shareholders, and support environmental goals that align with a more positive future.

Business Environment, Market Conditions and Outlook

Our operating and financial results, and those of the oil and gas industry as a whole, are heavily influenced by commodity prices. Oil and gas prices and differentials have, and may continue to, fluctuate significantly as a result of numerous market-related variables, including global geopolitical and economic conditions. As discussed below, our 2020 operating and financial results have been adversely impacted by the deterioration and prolonged weakness in commodity prices resulting from the COVID-19 pandemic and certain actions by foreign oil and gas producers. Commodity prices are currently expected to remain depressed for an extended period of time.

The extent to which our full year 2020 operating and financial results, or that of future periods, will be adversely impacted by the ongoing COVID-19 pandemic will depend largely on future developments, which are highly uncertain and cannot be accurately predicted. 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 future 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 and extent of the pandemic and speculation as to future actions by Saudi Arabia, Russia and other foreign producers. We have taken steps and continue to work to address the evolving challenges and mitigate mounting repercussions from both the COVID-19 pandemic and the industry downturn on our operations, our financial condition and our people. We continue to plan for a prolonged downturn well into 2021, in spite of recent slight improvements in oil prices. However, given the tremendous volatility and turmoil, there is no certainty that the measures we take will ultimately be sufficient.

The COVID-19 Pandemic and Industry Downturn

In December 2019, a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19, was reported to have surfaced in China. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic. The COVID-19 pandemic has caused significant disruption globally since January 2020 and the U.S. economy continues to experience profound 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. The oil and gas industry has been severely impacted by the steep and prolonged deterioration in the price of oil caused by the significant decrease in 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 first half of 2020.

In March 2020, 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 related to the COVID-19 pandemic coupled with a substantial increase in supply - drove oil prices to historically low levels and created significant volatility, uncertainty, and turmoil in the oil and gas industry. As a result, the price of oil was extremely depressed and even reached historic lows during the second quarter 2020, with the price of Brent crude bottoming to just under $20 per Bbl in mid April 2020. These market conditions prompted producers all over the world to shut-in production and delay new oil and gas projects. OPEC+ eventually announced production cuts in April 2020, and then in June 2020 agreed to extend the cuts through the end of July 2020. In August these production cuts were eased slightly and the current output reduction levels are expected to remain through the end of 2020.

Additionally, the effects of demand destruction with a supply surge globally was amplified during the second quarter 2020 as available storage for crude oil and refined products became increasingly limited and there were concerns that available storage could become completely unavailable in 2020 and beyond, depending on the duration and severity of the ongoing pandemic. With the storage and transportation constraints further adding to the pressure on commodities prices, during the second quarter 2020 refiners started to curtail output and producers all over the world - including in the United States - started to shut-in production. Toward the end of the second quarter 2020, oil prices began to recover as the production cuts reduced the supply overhang and global demand began to increase gradually with containment of the COVID-19 outbreak in areas around the globe. The storage concerns were partially relieved as a result. However, this recovery appears fragile and has flattened, with oil price recovery stalling and oil demand remaining below pre-COVID-19 pandemic levels. Demand, and pricing, may again decline due to the ongoing COVID-19 pandemic, particularly if there is a resurgence of the outbreak as some are suggesting is possible, although the extent of the additional impact on our industry and our business cannot be reasonably predicted at this time.

As we focus on managing our business and operations in response to this health and economic crisis, the safety and well-being of our employees and the communities in which we operate has been, and 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 have implemented recommended practices with respect to social distancing, quarantines, travel bans and other restrictions. Although we managed the transition to remote work arrangements and subsequent office reopening without a loss in business continuity, we incurred additional costs and experienced some inefficiencies; importantly, none of which had an impact on our 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. As discussed above, the situation remains volatile and, if there is a resurgence of the COVID-19 outbreak in our areas of operation, we may be forced to again temporarily close our offices and transition to work from home; although we currently expect our operations would continue as normal and without significant additional impact 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 safety and 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 we still have essentially all of our expected oil production hedged in the remainder of 2020 at nearly $60 per barrel. We have hedged the substantial majority of our expected first half of 2021 oil production and have hedged just less than half of expected production for the second half of 2021. Additionally in October 2020, we hedged 12,500 MMBtu/d of our 2021 Rockies gas production at nearly $3.00 per MMBtu. Low oil and gas prices are expected to continue for some period as reflected by the current futures forward curves for Brent crude and Henry Hub gas, and we have secured these hedge positions to protect against the anticipated prolonged weakness in commodity prices. However, ongoing or worsening economic impacts to our industry could adversely impact our financial results through 2021 or beyond.

We experienced a decrease in production for the second and third quarters of 2020, largely due to natural declines as a result of temporarily discontinuing our drilling activity in April and engaging proactive maintenance and well management activities. We restarted our drilling activity in mid-October 2020, which we currently expect to continue through 2021 if our financial position and market conditions continue to support it. As a result, capital spending for the full year 2020 is now expected to be approximately $72 million, excluding capitalized overhead. During the second quarter of 2020, we obtained additional storage capacity to support our planned production for the remainder of the year and into 2021. As market conditions improved, we released a portion of the capacity. We currently believe our storage capacity will be sufficient to support our current planned production and we do not anticipate shutting in production in the near future unless economics dictate. However, the risk remains that storage for oil may be unavailable and our existing capacity may be insufficient to support planned production rates in the event of demand for our oil deteriorating again or a supply surge or both. If we are unable to obtain additional storage capacity if needed, we could be forced to shut-in some or all of our production or delay or temporarily discontinue our drilling plans. This 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 how long storage remains filled and unavailable to us, which is also unknowable. 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.*"

Commodity Pricing and Differentials

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 higher for the three months ended September 30, 2020 compared to the three months ended June 30, 2020 but lower than the three months ended September 30, 2019. Brent crude oil contract prices ranged from $45.86 per Bbl to $39.61 per Bbl during the third quarter of 2020. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. During the second quarter of 2020, we experienced an adverse widening in the price differential between Brent and California crude due to the lack of local demand and storage capacity. This differential widening improved in the third quarter 2020 as the market storage concerns began to soften. As described above, if economic and health situations from the COVID-19 pandemic cause demand to worsen, and/or if OPEC+ producers take actions that again create a supply surge, and if necessary storage availability is not sufficient, oil prices may again 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 $12.69 per MMBtu and as low as $1.37 per MMBtu during the third quarter of 2020, while we paid an average of $2.84 per MMBtu in this period.

The following table presents the average Brent, WTI, Kern, Delivered, and Henry Hub prices for the three months ended September 30, 2020, June 30, 2020 and September 30, 2019 and for the nine months ended September 30, 2020 and September 30, 2019:

	Three Months Ended			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	September 30, 2020	September 30, 2019
Oil (Bbl) – Brent	$ 43.34	$ 33.39	$ 62.03	$ 42.53	$ 64.75
Oil (Bbl) – WTI	$ 40.87	$ 28.42	$ 56.33	$ 38.55	$ 57.03
Natural gas (MMBtu) – Kern, Delivered	$ 2.84	$ 1.45	$ 2.50	$ 2.15	$ 3.19
Natural gas (MMBtu) – Henry Hub	$ 2.00	$ 1.70	$ 2.38	$ 1.87	$ 2.62

As mentioned above, 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 and potential environmental impact 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, California oil prices are determined ultimately by local supply and demand dynamic. Even as Brent pricing fell, and was weak, due to the effects of demand destruction with a supply surge globally, we 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. We planned for significant deterioration of these differentials and refinery utilizations, and our plan for this expected worsening situation did not fully materialize, which enabled us to mitigate the impact. Although market conditions improved and the differential widening softened toward the end of the second quarter 2020, if California pricing weakens, our financial and operating results will be adversely affected. Currently we have storage capacity of 315,000 Bbls through June of 2021 to help mitigate these potential consequences.

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 California steamfloods and cogeneration facilities than we produce and sell in Utah and Colorado ("the Rockies"). Additionally, in recent history, the California gas markets have had higher gas prices than the Rockies and the rest of the United States. Consequently, higher gas prices have a negative impact on our operating results. 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 on our California operating expenses is partially offset by higher gas sales for the gas we produce in the Rockies.

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.

EH&S and Regulatory Matters

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. Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and abandonment requirements for the oil and natural gas industry could have a significant impact on operations. Federal, state, and local agencies may assert overlapping authority to regulate in these areas. 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.

In California, 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. For example:

- In April 2019 new idle well regulations went into effect, which include a comprehensive well testing regime to prevent leaks, a compliance schedule for testing or plugging and abandoning idle wells, the collection of data necessary to prioritize testing and sealing idle wells, requirements for a long-term idle well management plan, an engineering analysis for each well idled 15 years or longer, and requirements for active observation wells. In California, an idle well is one that has not been used for two years or more and has not yet been permanently sealed pursuant to regulations from California Geologic Energy Management Division ("CalGEM"), California's primary regulator of the oil and natural gas industry on private and state lands. We have submitted the required plans to meet our obligations.

- CalGEM’s predecessor also finalized new Underground Injection Control (“UIC”) regulations, effective April 2019, which affect two types of wells: (i) those that inject water or steam for enhanced oil recovery and (ii) those that return the briny groundwater that comes up from oil formations during production. These regulations include stronger testing requirements designed to identify potential leaks, increased data requirements to ensure proposed projects are fully evaluated, continuous well pressure monitoring, requirements to automatically cease injection when there is a risk to safety or the environment, and requirements to disclose chemical additives for injection wells close to water supply wells. Our California development and production activities are subject to these UIC regulations.

- Legislation passed in 2019 took effect January 1, 2020, including AB 1057, which requires state agencies to review emissions from idle and abandoned wells, and valuate plugging and abandonment and restoration costs and associated bonding requirements. This legislation also expanded CalGEM’s duties to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state’s energy needs.

- Additionally, in November 2019, California's Department of Conservation issued a press release announcing three actions by CalGEM: (1) a moratorium on approval of new high–pressure cyclic steam wells pending a study of the practice to address surface expressions experienced by certain operators; (2) review and updating of regulations regarding public health and safety near oil and natural gas operations pursuant to additional duties assigned to CalGEM by the Legislature in 2019; and (3) a performance audit of CalGEM's permitting processes for well stimulation treatment (“WST”) permits and project approval letters (“PALs”) for underground injection by the California Department of Finance and an independent review and approval of the technical content of pending WST and PAL applications by Lawrence Livermore National Laboratory. In January 2020, CalGEM issued a formal notice to operators, including us, that they had issued restrictions imposing a moratorium to prohibit new underground oil-extraction wells from using high-pressure cyclic steaming process. Only our undeveloped thermal diatomite assets are currently impacted by the moratorium. Our 2020 results have not been, and are not expected to be, significantly impacted by the moratorium because our 2020 development and production plans did not require new high-pressure cyclic steam injection and the moratorium does not impact existing production or previously approved permits.

- On September 23, 2020, California’s Governor Gavin Newsom issued Executive Order N-79-20 related to vehicular transportation emissions and fossil fuel production in California. The order establishes a number of new policy goals for the State of California and directs the state legislature and agencies to develop policies or conduct rulemakings in furtherance of these goals. Specifically, the order addresses (1) working to end the issuance of new hydraulic fracturing permits by 2024, (2) development of a plan to transition upstream and downstream oil facilities by July 2021, (3) the need for strict enforcement of bonding requirements and other oil and gas regulations by CalGEM, and (4) development of new, draft public health and safety rules by December 31, 2020. The potential impact on Berry will depend on the nature of any final rules, regulations, policies, or legislation adopted by the state agencies or passed by the state legislature. As such, impacts to Berry cannot be predicted at this time.

- Legislation passed in 2020 will take effect January 1, 2021, although emergency measures take effect immediately upon signature by the Governor. Legislation signed into law in 2020 includes expanded oil spill penalties, new reporting requirements for excavations and subsurface installations, new protections for workers and disclosure requirements related to COVID-19.

Violations and liabilities with respect to any of the applicable laws and regulations, including those related to any environmental incident, could result in significant administrative, civil, or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, an inability to receive permits, operational interruptions or shutdowns and other liabilities. Additionally, the costs of remedying any environmental incident may be significant, and remediation obligations could adversely affect our financial condition, results of operations and prospects. 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.

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.

Seasonality

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 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.

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. Marketing revenues represent sales of natural gas purchased from and sold to third parties. 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, production and abandonment plans, including by restricting the production rate of oil, natural gas and NGLs below the rate that would otherwise be possible. Additionally, the regulatory burden on the industry increases the cost of doing business and consequently effects capital expenditures and earnings.

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, and incentivize our employees to perform at high standards, including through our annual short-term incentive program.

General and Administrative Expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities and less than 10% of such costs are capitalized, which is significantly less than industry norms. 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 and nine months ended September 30, 2020, our capital expenditures were approximately $4 million and $57 million, respectively, on an accrual basis excluding capitalized overhead of approximately $1.5 million and $4.5 million, respectively. These amounts also excluded capitalized interest, acquisitions and asset retirement spending. Approximately 90% of total capital for the nine months ended September 30, 2020 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, coupled with OPEC+ actions, which created significant volatility, uncertainty, and turmoil in the oil and gas industry. Since that time, the 2020 capital expenditures have been focused on 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 2020 to ensure adequate inventory once we restarted our drilling program. With the slight strengthening of oil prices in the third quarter 2020, capital spending for the full year is now expected to be approximately $72 million, which excludes approximately $7 million of capitalized overhead. This includes restarting our drilling program in mid-October 2020, as well as increasing workover and recompletion opportunities during the fourth quarter 2020. The 2020 capital expenditures also includes approximately $25 million for facilities and cogen projects, including long-term maintenance, as well as approximately $4 million for drilling delineation wells which added value by increasing our reserves and drilling inventory for these projects.

We currently expect 2020 production to be flat with the prior year. We also anticipate oil production will be approximately 88% of total production in 2020, compared to 87% in 2019. Based on our current capital plan we expect to be able to fund our remaining 2020 capital development programs with cash flow from operations. Even in this low price environment we plan to live within Levered Free Cash Flow over 2020 and 2021 in the aggregate, 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 and not included in the capital expenditures noted above, for the full year 2020, we plan to spend approximately $16-$20 million on plugging and abandonment activities, including satisfying our annual obligations under the California Idle Well Management Program. This includes the $14 million spent in the first three quarters of 2020.

Acquisition

In May 2020, we acquired approximately 740 net acres in the North Midway Sunset Field for approximately $5 million. We paid $2 million at closing and the remaining $3 million was paid following our first production from this property, in the fourth quarter 2020. This property is adjacent to, and extends, our existing producing area and we have identified numerous future drilling locations. We believe additional opportunities exist in other productive reservoirs of this property. We also acquired all existing idle wells on this property, some of which we plan to return to production in the near future as price and strategy dictate. We will plug and abandon the remaining idle wells pursuant to the California Idle Well Management Program. We recorded a $6 million liability for asset retirement obligations of the existing wells on this property.

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 September 30, 2020	California June 30, 2020	California September 30, 2019
Oil, natural gas and natural gas liquids sales	$ 81,592	$ 62,943	$ 124,540
Operating income [1]	$ 36,296	$ 32,469	$ 66,449
Depreciation, depletion, and amortization (DD&A)	$ 34,779	$ 36,518	$ 24,360
Average daily production (MBoe/d)	22.2	23.4	23.0
Production (oil % of total)	100 %	100 %	100 %
Realized sales prices:			
Oil (per Bbl)	$ 40.02	$ 29.53	$ 59.00
NGLs (per Bbl)	$ —	$ —	$ —
Gas (per Mcf)	$ —	$ —	$ —
Capital expenditures[2]	$ 4,467	$ 15,916	$ 59,076

($ in thousands, except prices)	Utah (Uinta basin) Three Months Ended September 30, 2020	Utah June 30, 2020	Utah September 30, 2019	Colorado (Piceance basin) Three Months Ended September 30, 2020	Colorado June 30, 2020	Colorado September 30, 2019
Oil, natural gas and natural gas liquids sales	$ 9,311	$ 6,439	$ 14,946	$ 1,336	$ 1,132	$ 1,758
Operating income (loss)[1]	$ 1,093	$ (584)	$ 1,376	$ (235)	$ 6	$ (123)
Depreciation, depletion, and amortization (DD&A)	$ 915	$ 905	$ 3,039	$ 165	$ 43	$ 264
Average daily production (MBoe/d)	4.1	4.4	5.1	1.3	1.3	1.5
Production (oil % of total)	47 %	49 %	52 %	2 %	2 %	2 %
Realized sales prices:						
Oil (per Bbl)	$ 38.40	$ 23.11	$ 48.74	$ 33.60	$ 20.67	$ 56.18
NGLs (per Bbl)	$ 13.25	$ 5.82	$ 12.10	$ —	$ —	$ —
Gas (per Mcf)	$ 2.05	$ 1.68	$ 2.21	$ 1.80	$ 1.53	$ 1.99
Capital expenditures[2]	$ 103	$ 82	$ 1,851	$ 46	$ 145	$ 213

(1) Operating income (loss) includes oil, natural gas and NGL sales, and scheduled oil derivative settlements, offset by operating expenses (as defined elsewhere), 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		
	September 30, 2020	June 30, 2020	September 30, 2019
Average daily production:[(1)]			
Oil (MBbl/d)	24.1	25.6	25.7
Natural Gas (MMcf/d)	18.7	19.2	20.9
NGL (MBbl/d)	0.4	0.3	0.4
Total (MBoe/d)[(2)]	27.6	29.1	29.6
Total Production:			
Oil (MBbl)	2,218	2,330	2,360
Natural gas (MMcf)	1,719	1,746	1,920
NGLs (MBbl)	33	29	39
Total (MBoe)[(2)]	2,537	2,650	2,719
Weighted-average realized sales prices:			
Oil without hedges ($/Bbl)	$ 39.88	$ 28.98	$ 57.92
Effects of scheduled derivative settlements ($/Bbl)	$ 16.28	$ 25.42	$ 7.31
Oil with hedges ($/Bbl)	$ 56.16	$ 54.40	$ 65.23
Natural gas ($/Mcf)	$ 1.95	$ 1.62	$ 2.12
NGL ($/Bbl)	$ 13.25	$ 5.82	$ 12.10
Average Benchmark prices:			
Oil (Bbl) – Brent	$ 43.34	$ 33.39	$ 62.03
Oil (Bbl) – WTI	$ 40.87	$ 28.42	$ 56.33
Natural gas (MMBtu) – Kern, Delivered[(3)]	$ 2.84	$ 1.45	$ 2.50
Natural gas (MMBtu) – Henry Hub[(4)]	$ 2.00	$ 1.70	$ 2.38

(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 September 30, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.34 per Bbl and $2.00 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		
	September 30, 2020	June 30, 2020	September 30, 2019
Average daily production (MBoe/d):[(1)]			
California	22.2	23.4	23.0
Utah	4.1	4.4	5.1
Colorado	1.3	1.3	1.5
Total average daily production	27.6	29.1	29.6

(1) Production represents volumes sold during the period.

Average daily production decreased 1.5 MBoe/d, or 5%, for the three months ended September 30, 2020, compared to the three months ended June 30, 2020, largely due to natural declines as a result of temporarily discontinuing our drilling activity in April 2020. Further, we experienced seasonal disruptions and undertook certain operational improvements that caused temporary reductions in our production. Notably, we performed some plugging and abandonment activity that resulted in temporary shut-in of nearby wells. Additionally, we improved steam management which reduced overall costs but temporarily increased water disposal and well maintenance needs, resulting in a slight decrease in production. Our California production of 22.2 MBoe/d for the third quarter 2020 decreased 5% from the second quarter 2020.

Average daily production volumes decreased 7% for the three months ended September 30, 2020 as compared to the three months ended September 30, 2019 due to significantly reduced development capital spending in the second and third quarter 2020 compared to the same quarters in 2019. This year-over-year decrease was also impacted by the same reasons noted above.

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

	Nine Months Ended	
	September 30, 2020	September 30, 2019
Average daily production:[1]		
Oil (MBbl/d)	25.7	24.5
Natural Gas (MMcf/d)	18.8	20.4
NGL (MBbl/d)	0.3	0.4
Total (MBoe/d)[2]	29.1	28.3
Total Production:		
Oil (MBbl)	7,033	6,673
Natural gas (MMcf)	5,148	5,565
NGLs (MBbl)	94	116
Total (MBoe)[2]	7,985	7,717
Weighted-average realized sales prices:		
Oil without hedges ($/Bbl)	$ 39.00	$ 58.79
Effects of scheduled derivative settlements ($/Bbl)	$ 16.97	$ 4.30
Oil with hedges ($/Bbl)	$ 55.97	$ 63.09
Natural gas ($/Mcf)	$ 1.85	$ 2.67
NGL ($/Bbl)	$ 10.92	$ 17.74
Average Benchmark prices:		
Oil (Bbl) – Brent	$ 42.53	$ 64.75
Oil (Bbl) – WTI	$ 38.55	$ 57.03
Gas (MMBtu) – Kern, Delivered[3]	$ 2.15	$ 3.19
Natural gas (MMBtu) – Henry Hub[4]	$ 1.87	$ 2.62

(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, during the nine months ended September 30, 2020, the average prices of Brent oil and Henry Hub natural gas were $42.53 per Bbl and $1.87 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:

	Nine Months Ended	
	September 30, 2020	September 30, 2019
Average daily production (MBoe/d):[1]		
California	23.5	21.6
Utah	4.3	5.2
Colorado	1.3	1.5
Total average daily production	29.1	28.3

(1) Production represents volumes sold during the period.

Average daily production increased 3% for the nine months ended September 30, 2020, compared to the nine months ended September 30, 2019, largely due to the impact of our development program in late 2019 and into the first quarter of this year. Our California production of 23.5 MBoe/d for the nine months September 30, 2020 increased 9% compared to the nine months ended September 30, 2019 where the majority of our capital in 2019 and 2020 was spent. Of the 23 California wells drilled in the first half of 2020, twelve were producing wells, nine were delineation and two were injector wells. This overall increase was also impacted by the same issues identified above in the third quarter to second quarter 2020 section. The production in Utah and Colorado decreased 16% for the nine months ended September 30, 2020 compared to the same period in 2019, primarily due to a lack of capital expenditures and natural decline.

Results of Operations

Three Months Ended September 30, 2020 compared to Three Months Ended June 30, 2020.

	Three Months Ended			
	September 30, 2020	June 30, 2020	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 92,239	$ 70,515	$ 21,724	31 %
Electricity sales	8,744	4,884	3,860	79 %
(Losses) gains on oil derivatives	(11,564)	(42,267)	30,703	(73)%
Marketing and other revenues	330	321	9	3 %
Total revenues and other	$ 89,749	$ 33,453	$ 56,296	168 %

Revenues and Other

Oil, natural gas and NGL sales increased by $22 million, or 31%, to approximately $92 million for the three months ended September 30, 2020, compared to the three months ended June 30, 2020. The increase was driven by $24 million of higher oil prices partially offset by lower oil volumes.

Electricity sales represent sales to utilities, and increased $4 million, or 79%, to approximately $9 million for the three months ended September 30, 2020 compared to the three months ended June 30, 2020. The increase primarily reflected higher unit sales prices that resulted from a seasonal increase in capacity payments and higher natural gas prices during the third quarter 2020 compared to the second quarter 2020.

Gain or loss on oil derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement gains for the three months ended September 30, 2020 and June 30, 2020 were $36 million and $59 million, respectively. The quarter-over-quarter decrease in settlement gains was driven by higher oil prices relative to the derivative fixed contract prices in the third quarter compared to those of the second quarter of 2020. Each of these quarters had the same average derivative fixed prices and daily notional volumes. The mark-to-market non-cash loss of $48 million for the three months ended September 30, 2020 was due to higher futures prices relative to the derivative fixed prices at September 30, 2020 compared to the non-cash loss of $101 million for the three months ended June 30, 2020.

Marketing and other revenues were comparable for the periods presented.

	Three Months Ended			
	September 30, 2020	June 30, 2020	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 45,243	$ 40,733	$ 4,510	11 %
Electricity generation expenses	4,217	3,022	1,195	40 %
Transportation expenses	1,768	1,789	(21)	(1)%
Marketing expenses	326	280	46	16 %
General and administrative expenses	19,173	18,777	396	2 %
Depreciation, depletion and amortization	35,905	37,512	(1,607)	(4)%
Taxes, other than income taxes	9,913	10,449	(536)	(5)%
(Gain) losses on natural gas derivatives	(15,784)	925	(16,709)	n/a
Other operating expenses (income)	1,648	(1,192)	2,840	n/a
Total expenses and other	102,409	112,295	(9,886)	(9)%
Other (expenses) income:				
Interest expense	(8,391)	(8,676)	285	(3)%
Other, net	(3)	(6)	3	(50)%
Loss before income taxes	(21,054)	(87,524)	66,470	(76)%
Income tax (benefit) expense	(2,190)	(22,623)	20,433	(90)%
Net loss	$ (18,864)	$ (64,901)	$ 46,037	(71)%
Expenses per Boe:[(1)]				
Lease operating expenses	$ 17.83	$ 15.37	$ 2.46	16 %
Electricity generation expenses	1.66	1.14	0.52	46 %
Electricity sales[(1)]	(3.45)	(1.84)	(1.61)	88 %
Transportation expenses	0.69	0.67	0.02	3 %
Transportation sales[(1)]	—	(0.01)	0.01	(100)%
Marketing expenses	0.13	0.11	0.02	18 %
Marketing revenues[(1)]	(0.13)	(0.11)	(0.02)	18 %
Derivatives settlements paid for gas purchases[(1)]	0.24	2.78	(2.54)	(91)%
Total operating expenses	$ 16.97	$ 18.11	$ (1.14)	(6)%
Total unhedged operating expenses[(2)]	$ 16.73	$ 15.33	$ 1.40	9 %
Total non-energy operating expenses[(4)]	$ 13.34	$ 12.81	$ 0.53	4 %
Total energy operating expenses[(5)]	$ 3.65	$ 5.30	$ (1.65)	(31)%
General and administrative expenses[(3)]	$ 7.56	$ 7.09	$ 0.47	7 %
Depreciation, depletion and amortization	$ 14.15	$ 14.16	$ (0.01)	— %
Taxes, other than income taxes	$ 3.91	$ 3.94	$ (0.03)	(1)%

(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 $2.08 per Boe and $1.77 per Boe for the three months ended September 30, 2020 and June 30, 2020, 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 a hedged basis, operating expenses, decreased 6% or $1.14 per Boe to $16.97 in the third quarter 2020 from $18.11 in the second quarter 2020. The decrease was largely due to higher electricity sales resulting from higher seasonal capacity payments. During the third quarter 2020, we sustained the cost savings achieved in the first half of 2020, as hedged fuel and non-fuel costs were essentially flat to the second quarter 2020. On an unhedged basis, operating expenses increased by 9% or $1.40 per Boe to $16.73 for the third quarter 2020, compared to $15.33 for the second quarter 2020. This increase was driven by higher unhedged fuel costs in comparison to the second quarter 2020.

Lease operating expenses per Boe increased to $17.83, for the three months ended September 30, 2020, a 16% or $2.46 per Boe increase compared to $15.37 per Boe for the three months ended June 30, 2020 driven by higher unhedged fuel costs related to our California steam operations. Unhedged fuel cost increased $2.31 per Boe, or 65% in the third quarter 2020 from $3.54 for the three months ended June 30, 2020. Non-fuel lease operating expense increased $0.15 per Boe due to lower sales volumes while spending on an absolute dollar basis was $1 million lower including lower facilities gas compression, oil and water processing costs. Lease operating expenses include 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 increased approximately 46% to $1.66 per Boe for the three months ended September 30, 2020, compared to $1.14 per Boe for the three months ended June 30, 2020 due to higher natural gas costs described above and lower sales volumes. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Gains and losses on natural gas purchase derivatives resulted in a $16 million gain for the three months ended September 30, 2020 and a loss of $1 million in the three months ended June 30, 2020. Settlement losses for each of the three months ended September 30, 2020 and June 30, 2020 were $1 million and $7 million, or $0.24 and $2.78 per Boe, respectively, and decreased due to higher gas prices. The mark-to-market valuation gain for the three months ended September 30, 2020 was $17 million compared to a $6 million gain for the prior quarter. Generally, because we are the fixed price payer on these natural gas swaps, increases in the associated futures prices will result in valuation gains.

Transportation expenses were essentially flat at $0.69 per Boe for the three months ended September 30, 2020 compared to $0.67 per Boe for the three months ended June 30, 2020.

Marketing expenses were comparable for the three months ended September 30, 2020 and June 30, 2020.

General and administrative expenses increased by $0.4 million, or 2%, to $19 million for the three months ended September 30, 2020, compared to the three months ended June 30, 2020. For the three months ended September 30, 2020 and June 30, 2020, general and administrative expenses included non-cash stock compensation costs of approximately $3.8 million and $4.4 million, respectively, and certain non-recurring costs of approximately $1.5 million and $0.3 million, respectively. Non-cash stock compensation expense declined from the second quarter 2020 due to the awards that expired or were forfeited in the third quarter 2020 and had been fully expensed at that time. The third quarter 2020 non-recurring costs mainly consisted of costs related to the retirement of former Chief Operating Officer ("COO") and hiring of new COO. Less than 10% of our overhead is capitalized and thus excluded from general and administrative expenses.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, were $14 million for each of the three month periods ended September 30, 2020 and June 30, 2020. These cost levels include a slight reduction in headcount since early 2020, although none of these reductions are a result of the current economic environment. 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.

DD&A decreased by $2 million or 4% to approximately $36 million for the three months ended September 30, 2020 compared to the three months ended June 30, 2020. This decrease is attributable to the reduced sales volumes period-over-period.

Taxes, Other Than Income Taxes

	Three Months Ended			
	September 30, 2020	June 30, 2020	$ Change	% Change
	(per Boe)			
Severance taxes	$ 0.82	$ 0.70	$ 0.12	17 %
Ad valorem and property taxes	1.60	1.39	0.21	15 %
Greenhouse gas allowances	1.49	1.85	(0.36)	(19)%
Total taxes other than income taxes	$ 3.91	$ 3.94	$ (0.03)	(1)%

Taxes, other than income taxes, decreased in the three months ended September 30, 2020 by $0.03 per Boe, or 1%, to $3.91. Greenhouse gas ("GHG") costs were lower in the third quarter of 2020 as the prices remained relatively flat while the emission volumes declined. During the third quarter 2020, we experienced higher property tax rates, as well as higher severance tax rates due to the expiration of certain deductions. These changes were also impacted by the decrease in sales volumes in the third quarter 2020.

Other Operating (Income) Expenses

Other operating expenses for the three months ended September 30, 2020 was $2 million comprised mainly of excess abandonment costs and excess storage capacity obtained in response to global oil storage concerns. Other operating income of $1 million for the three months ended June 30, 2020 included refunds from sales taxes paid in prior years and resolved claims from our prior parent company's bankruptcy.

Interest Expense

Interest expense was relatively flat at $8 million for each of the three months ended September 30, 2020 and June 30, 2020.

Income Tax (Benefit) Expense

Our effective tax rate was approximately 10% and 26% for the three months ended September 30, 2020 and June 30, 2020, respectively. The rate in the third quarter 2020 was negatively impacted by adjustments to our valuation allowance during the quarter related to current year losses and expected future realizability of deferred tax assets.

Three Months Ended September 30, 2020 compared to Three Months Ended September 30, 2019.

	Three Months Ended September 30,			
	2020	2019	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 92,239	$ 141,250	$ (49,011)	(35)%
Electricity sales	8,744	7,460	1,284	17 %
(Losses) gains on oil derivatives	(11,564)	45,509	(57,073)	n/a
Marketing and other revenues	330	453	(123)	(27)%
Total revenues and other	$ 89,749	$ 194,672	$ (104,923)	(54)%

Revenues and Other

Oil, natural gas and NGL sales decreased by $49 million, or 35% to approximately $92 million for the three months ended September 30, 2020 when compared to the three months ended September 30, 2019. This variance was driven by $40 million of lower commodity prices, as well as $9 million of lower volumes.

Electricity sales represent sales to utilities, and increased by $1.3 million, or 17%, to approximately $9 million for the three months ended September 30, 2020 when compared to the three months ended September 30, 2019. The increase was equally split between higher unit sales prices and higher sales volumes.

Gain or loss on oil derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement gains for the three months ended September 30, 2020 and September 30, 2019 were $36 million and $17 million, respectively. The quarter-over-quarter increase in settlement gains was driven by lower oil prices relative to our derivative fixed contract prices and more volumes hedged in the third quarter of 2020 compared to the third quarter of 2019. The mark-to-market non-cash loss of $48 million for the three months ended September 30, 2020 was due to higher futures prices relative to our derivative fixed contract prices at September 30, 2020. The mark-to-market non-cash gain of $29 million for the three months ended September 30, 2019, was primarily due to lower futures prices relative to our derivative fixed contract prices at September 30, 2019.

Marketing and other revenues were comparable for the periods presented.

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 45,243	$ 50,957	$ (5,714)	(11)%
Electricity generation expenses	4,217	3,781	436	12 %
Transportation expenses	1,768	2,067	(299)	(14)%
Marketing expenses	326	398	(72)	(18)%
General and administrative expenses	19,173	16,434	2,739	17 %
Depreciation, depletion and amortization	35,905	27,664	8,241	30 %
Taxes, other than income taxes	9,913	9,249	664	7 %
(Gain) losses on natural gas derivatives	(15,784)	3,008	(18,792)	n/a
Other operating expenses (income)	1,648	(550)	2,198	n/a
Total expenses and other	102,409	113,008	(10,599)	(9)%
Other (expenses) income:				
Interest expense	(8,391)	(8,597)	206	(2)%
Other, net	(3)	(77)	74	(96)%
Reorganization items, net	—	(170)	170	(100)%
(Loss) income before income taxes	(21,054)	72,820	(93,874)	n/a
Income tax (benefit) expense	(2,190)	20,171	(22,361)	n/a
Net (loss) income	$ (18,864)	$ 52,649	$ (71,513)	n/a
Expenses per Boe:[(1)]				
Lease operating expenses	$ 17.83	$ 18.74	$ (0.91)	(5)%
Electricity generation expenses	1.66	1.39	0.27	19 %
Electricity sales[(1)]	(3.45)	(2.74)	(0.71)	26 %
Transportation expenses	0.69	0.76	(0.07)	(9)%
Transportation sales[(1)]	—	(0.01)	0.01	(100)%
Marketing expenses	0.13	0.15	(0.02)	(13)%
Marketing revenues[(1)]	(0.13)	(0.15)	0.02	(13)%
Derivatives settlements paid for gas purchases[(1)]	0.24	0.77	(0.53)	(69)%
Total operating expenses	$ 16.97	$ 18.90	$ (1.93)	(10)%
Total unhedged operating expenses[(2)]	$ 16.73	$ 18.13	$ (1.40)	(8)%
Total non-energy operating expenses[(4)]	$ 13.34	$ 14.09	$ (0.75)	(5)%
Total energy operating expenses[(5)]	$ 3.65	$ 4.81	$ (1.16)	(24)%
General and administrative expenses[(3)]	$ 7.56	$ 6.04	$ 1.52	25 %
Depreciation, depletion and amortization	$ 14.15	$ 10.17	$ 3.98	39 %
Taxes, other than income taxes	$ 3.91	$ 3.40	$ 0.51	15 %

(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 $2.08 per Boe and $0.91 per Boe for the three months ended September 30, 2020 and September 30, 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, including hedge effects, decreased by 10% or $1.93 per Boe to $16.97 per Boe for the third quarter 2020 compared to $18.90 per Boe for the third quarter 2019. This decrease included $0.91 per Boe lower lease operating expenses and $0.44 of higher electricity sales margin and $0.53 per Boe of more favorable gas hedge settlements in 2020. Additionally, operating expenses, on an unhedged basis, were 8%, or $1.40 per Boe lower for the three months ended September 30, 2020 compared to the three months ended September 30, 2019 due to these same non-hedge factors.

As a result of our 2020 cost savings and efficiency initiatives, we experienced a positive and substantial impact on lease operating expenses in 2020 when compared to 2019. Lease operating expenses were $17.83 per Boe for the three months ended September 30, 2020, a 5% or $0.91 per Boe reduction compared to $18.74 for the three months ended September 30, 2019. Non-fuel lease operating expense decreases included $0.65 of lower costs related to maintenance, as well as $0.46 in facilities gas compression and oil and water processing costs. On an absolute dollar basis, non-fuel lease operating expenses declined $4 million in the third quarter 2020 compared to the same period last year. Lease operating fuel cost related to our California steam operations were unchanged during the third quarter 2020 from the same quarter 2019 due to more efficient steam consumption per Boe, which offset higher natural gas prices. Lease operating expenses include fuel, maintenance, labor including supervision, vehicles, workover expenses, field office, tools and supplies. Fuel costs excluded the effects of natural gas derivative settlements discussed below.

Electricity generation expenses increased approximately 19% to $1.66 per Boe for the three months ended September 30, 2020 from $1.39 per Boe for the same period in 2019 primarily due to higher natural gas costs previously mentioned, as well as the impact of lower Boe volumes. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements.

Gains and losses on natural gas purchase derivatives for the three months ended September 30, 2020 and September 30, 2019 resulted in a gain of $16 million and a loss of $3 million, respectively. Settlement losses for each of the three months ended September 30, 2020 and 2019, were $1 million and $2 million, or $0.24 and $0.77 per Boe, respectively, and decreased due to higher gas prices during 2020. The mark-to-market valuation gain for the three months ended September 30, 2020 was $17 million compared to $1 million of loss for the same period in 2019, consistent with the changes in futures prices at the end of each period. Because we are the fixed price payer on these natural gas swaps, generally, increases in the associated price index creates valuation gains.

Transportation expenses were down $0.07 per Boe to $0.69 for the three months ended September 30, 2020 compared to the three months ended September 30, 2019 as a result of lower natural gas sales volumes.

Marketing expenses decreased 13% to $0.13 per Boe for the three months ended September 30, 2020, compared to $0.15 per Boe for the three months ended September 30, 2019 mostly due to lower gas prices.

General and administrative expenses increased $3 million, or 17%, to approximately $19 million for the three months ended September 30, 2020 compared to the three months ended September 30, 2019. For the three months ended September 30, 2020 and September 30, 2019, general and administrative expenses included non-cash stock compensation costs of approximately $3.8 million and $2.3 million, respectively, and non-recurring costs of approximately $1.5 million and $0.2 million, respectively.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, were $14 million for each of the three month periods ended September 30, 2020 and September 30, 2019.

DD&A increased $8 million, or 30%, to approximately $36 million for the three months ended September 30, 2020 compared to the three months ended September 30, 2019, primarily due to higher depreciation and depletion rates for 2020, partially offset by lower sales volumes. On a per Boe basis, period-over-period DD&A increased $3.98 to $14.15 from $10.17 due to our increasing capital development program throughout 2019 and the first quarter of 2020, compared to prior periods.

Taxes, Other Than Income Taxes

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	$ Change	% Change
	(per Boe)			
Severance taxes	$ 0.82	$ 0.67	$ 0.15	22 %
Ad valorem and property taxes	1.60	1.23	0.37	30 %
Greenhouse gas allowances	1.49	1.50	(0.01)	(1)%
Total taxes other than income taxes	$ 3.91	$ 3.40	$ 0.51	15 %

Taxes, other than income taxes increased 15% to $3.91 per Boe for the three months ended September 30, 2020 compared to $3.40 per Boe for the three months ended September 30, 2019. The increase was largely due to higher property tax rates combined with lower sales volumes, as well as increased severance tax rates due to the expiration of certain deductions in 2020.

Other Operating (Income) Expenses

Other operating expenses for the three months ended September 30, 2020 was $2 million, comprised mainly of excess abandonment costs and excess storage capacity obtained in response to global oil storage concerns. Other operating income for the three months ended September 30, 2019 were $1 million and consisted mainly of excess abandonment costs.

Interest Expense

Interest expense was comparable in the three months ended September 30, 2020 and September 30, 2019.

Reorganization items, net

Reorganization items, net were not material for the three months ended September 30, 2020 and September 30, 2019.

Income Tax (Benefit) Expense

Our effective tax rate was 10% for the three months ended September 30, 2020 compared to the 28% for the three months ended September 30, 2019. The rate in the third quarter 2020 was negatively impacted by adjustments to our valuation allowance during the quarter related to current year losses and expected future realizability of deferred tax assets.

Nine Months Ended September 30, 2020 compared to Nine Months Ended September 30, 2019.

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 284,852	$ 409,259	$ (124,407)	(30)%
Electricity sales	19,089	22,553	(3,464)	(15)%
Gains on oil derivatives	157,398	7,546	149,852	n/a
Marketing and other revenues	1,128	1,918	(790)	(41)%
Total revenues and other	$ 462,467	$ 441,276	$ 21,191	5 %

Revenues and Other

Oil, natural gas and NGL sales decreased by $124 million, or 30% to approximately $285 million for the nine months ended September 30, 2020 when compared to the nine months ended September 30, 2019. The decrease was driven by $139 million attributable to lower oil prices and $4 million attributable to lower gas prices. These decreases were partially offset by approximately $21 million attributable to higher oil volumes.

Electricity sales which represent sales to utilities decreased $3 million or 15% to $19 million for the nine months ended September 30, 2020 when compared to the nine months ended September 30, 2019. The decrease was mostly due to lower unit sales prices that were driven by lower natural gas prices.

Gain or loss on oil derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement gains for the nine months ended September 30, 2020 and September 30, 2019 were $119 million and $29 million, respectively. The increase in settlement gains was driven by lower oil prices relative to the derivative fixed prices and more volumes hedged in the nine months ended September 30, 2020 compared to the nine months ended September 30, 2019. The mark-to-market non-cash gain of $38 million for the nine months ended September 30, 2020 was due to lower futures prices relative to the derivative fixed prices at September 30, 2020. The loss of $21 million for the nine months ended September 30, 2019, was primarily due to higher futures prices relative to the derivative fixed prices at September 30, 2019.

Marketing and other revenues were lower for the nine months ended September 30, 2020, compared to the nine months ended September 30, 2019 due to lower average gas prices.

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	$ Change	% Change
	(in thousands, except expenses per Boe)			
Expenses and other:				
Lease operating expenses	$ 136,727	$ 156,765	$ (20,038)	(13)%
Electricity generation expenses	11,186	14,705	(3,519)	(24)%
Transportation expenses	5,379	5,935	(556)	(9)%
Marketing expenses	1,036	1,670	(634)	(38)%
General and administrative expenses	57,287	46,932	10,355	22 %
Depreciation, depletion and amortization	108,746	75,904	32,842	43 %
Impairment of oil and gas properties	289,085	—	289,085	100 %
Taxes, other than income taxes	24,714	28,683	(3,969)	(14)%
(Gain) losses on natural gas derivatives	(2,824)	10,342	(13,166)	n/a
Other operating expenses	2,658	3,814	(1,156)	(30)%
Total expenses and other	633,994	344,750	289,244	84 %
Other (expenses) income:				
Interest expense	(25,987)	(26,362)	375	(1)%
Other, net	(15)	79	(94)	n/a
Reorganization items, net	—	(426)	426	(100)%
(Loss) income before income taxes	(197,529)	69,817	(267,346)	n/a
Income tax expense (benefit)	1,536	19,294	(17,758)	(92)%
Net (loss) income	$ (199,065)	$ 50,523	$ (249,588)	n/a
Expenses per Boe:[1]				
Lease operating expenses	$ 17.12	$ 20.31	$ (3.19)	(16)%
Electricity generation expenses	1.40	1.91	(0.51)	(27)%
Electricity sales[1]	(2.39)	(2.92)	0.53	(18)%
Transportation expenses	0.67	0.77	(0.10)	(13)%
Transportation sales[1]	(0.01)	(0.03)	0.02	(67)%
Marketing expenses	0.13	0.22	(0.09)	(41)%
Marketing revenues[1]	(0.12)	(0.21)	0.09	(43)%
Derivatives settlements paid (received) for gas purchases[1]	1.55	0.25	1.30	n/a
Total operating expenses	$ 18.35	$ 20.28	$ (1.93)	(10)%
Total unhedged operating expenses[2]	$ 16.80	$ 20.03	$ (3.23)	(16)%
Total non-energy operating expenses[4]	$ 13.41	$ 14.75	$ (1.34)	(9)%
Total energy operating expenses[5]	$ 4.94	$ 5.54	$ (0.60)	(11)%
General and administrative expenses[3]	$ 7.17	$ 6.08	$ 1.09	18 %
Depreciation, depletion and amortization	$ 13.62	$ 9.84	$ 3.78	38 %
Taxes, other than income taxes	$ 3.10	$ 3.72	$ (0.62)	(17)%

(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 $1.85 per Boe and $1.18 per Boe for the nine months ended September 30, 2020 and September 30, 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, including hedge effects, decreased 10% or $1.93 per Boe to $18.35 for the nine months ended September 30, 2020 from $20.28 per Boe for the nine months ended September 30, 2019 due to $3.19 per Boe lower lease operating expenses, partially offset by $1.30 per Boe of higher gas hedge settlement losses and $0.02 decrease in electricity sales margin. Additionally, operating expenses, on an unhedged basis were $16.80 per Boe for the nine months ended September 30, 2020 which was approximately 16% lower than the nine months ended September 30, 2019 due to these same non-hedge factors.

Lease operating expenses decreased to $17.12 per Boe for the nine months ended September 30, 2020, a 16% or $3.19 per Boe reduction compared to $20.31 for the nine months ended September 30, 2019. The decrease was driven primarily by lower unhedged fuel prices related to our California steam operations and other cost savings. Unhedged fuel cost decreased $2.01 per Boe during the nine months ended September 30, 2020 from $6.81 in the same period of 2019 as natural gas prices declined 30%. Compared to the nine months ended September 30, 2019, the 2020 lease operating non-fuel expenses decreased $1.18, or $6 million on an absolute dollar basis, primarily due to cost savings initiatives and efficiency measures implemented beginning in the second quarter of 2020. These initiatives resulted in lower maintenance and outside services costs of $1.22 per Boe when compared to the nine months ended September 30, 2019. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Electricity generation expenses decreased approximately 27% to $1.40 per Boe for the nine months ended September 30, 2020 from $1.91 per Boe for the same period in 2019 primarily driven by lower fuel cost. Decreased fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements discussed elsewhere.

Gain or loss on natural gas purchase derivatives for the nine months ended September 30, 2020 and September 30, 2019 was a gain of $3 million and a loss of $10 million, respectively. The settlement loss for the nine months ended September 30, 2020 was $12 million, or $1.55 per Boe, compared to a settlement loss of $2 million, or $0.25 per Boe for same period in 2019, consistent with the changes in futures prices at the end of each period. The mark-to-market valuation gain or loss for each of the periods ended September 30, 2020 and September 30, 2019 was a gain of $15 million and a loss of $8 million respectively.

Transportation expenses decreased 13% to $0.67 per Boe for the nine months ended September 30, 2020, compared to $0.77 per Boe for the nine months ended September 30, 2019, mainly due to lower volumes shipped from our Rockies assets.

Marketing expenses decreased 41% to $0.13 per Boe for the nine months ended September 30, 2020, compared to $0.22 per Boe for the nine months ended September 30, 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 and sold to third parties.

General and administrative expenses increased by approximately $10 million, or 22%, for the nine months ended September 30, 2020 compared to the nine months ended September 30, 2019. For the nine months ended September 30, 2020 and September 30, 2019, general and administrative expenses included non-cash stock compensation costs of approximately $11 million and $6 million, respectively, and non-recurring costs of approximately $4 million and $3 million, respectively.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, were $43 million for the nine months ended September 30, 2020 compared to $38 million for the nine months ended September 30, 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 $33 million, or 43%, to approximately $109 million for the nine months ended September 30, 2020 compared to the nine months ended September 30, 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 $3.78 to $13.62 from $9.84 due to our increasing capital development program throughout 2019 and the first quarter of 2020, compared to prior periods.

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 for the nine months ended September 30, 2020.

Taxes, Other Than Income Taxes

	Nine Months Ended September 30,			
	2020	2019	$ Change	% Change
	(per Boe)			
Severance taxes	$ 0.74	$ 0.57	$ 0.17	30 %
Ad valorem and property taxes	1.46	1.31	0.15	11 %
Greenhouse gas allowances	0.90	1.84	(0.94)	(51)%
Total taxes other than income taxes	$ 3.10	$ 3.72	$ (0.62)	(17)%

Taxes, other than income taxes decreased $0.62 to $3.10 per Boe for the nine months ended September 30, 2020 compared to $3.72 per Boe for the nine months ended September 30, 2019. The decrease was largely due to lower greenhouse gas prices during 2020 including some allowance purchases we made at low prices due to a temporary market dislocation in the first quarter 2020. During 2020, we experienced higher property tax rates, as well as higher severance tax rates due to the expiration of certain deductions. These changes were also positively impacted by the increase in sales volumes during the nine months ended September 30, 2020 compared to the same period in 2019.

Other Operating Expenses (Income)

Other operating expenses for the nine months ended September 30, 2020 were $3 million including excess abandonment costs, drilling rig standby costs due to deferred drilling activity, and inventory storage costs, partially offset by refunds from sales taxes paid in prior years and resolved claims from our prior parent company's bankruptcy. Other operating expenses for the nine months ended September 30, 2019 were $4 million and were mostly comprised of excess abandonment costs.

Interest Expense

Interest expense was comparable in the nine months ended September 30, 2020 and September 30, 2019.

Reorganization items, net

Reorganization items, net were not material for the nine months ended September 30, 2020 and September 30, 2019.

Income Tax Expense (Benefit)

Our effective tax rate was (1)% and 28% for the nine months ended September 30, 2020 and September 30, 2019, respectively. The rate in 2020 was negatively impacted as we have recorded a valuation allowance on a large portion of our tax credits recorded in 2019 and on other deferred tax assets as a result of current year losses and changes during the year related to future realizability.

Non-GAAP Financial Measures

Adjusted EBITDA, Levered Free Cash Flow, 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 non-cash stock compensation expense and restructuring and other non-recurring costs. 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			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	September 30, 2020	September 30, 2019
			(in thousands)		
Adjusted EBITDA reconciliation to net income (loss):					
Net (loss) income	$ (18,864)	$ (64,901)	$ 52,649	$ (199,065)	$ 50,523
Add (Subtract):					
Interest expense	8,391	8,676	8,597	25,987	26,362
Income tax (benefit) expense	(2,190)	(22,623)	20,171	1,536	19,294
Depreciation, depletion and amortization	35,905	37,512	27,664	108,746	75,904
Impairment of oil and gas properties	—	—	—	289,085	—
Derivative (gains) losses	(4,220)	43,192	(42,501)	(160,222)	2,796
Net cash received for scheduled derivative settlements	35,476	51,874	15,153	106,975	26,731
Other operating expense (income)	1,648	(1,192)	(550)	2,658	3,814
Stock compensation expense	3,896	4,579	2,360	11,397	6,277
Non-recurring costs	1,473	316	219	3,651	3,061
Reorganization items, net	—	—	170	—	426
Adjusted EBITDA	$ 61,515	$ 57,433	$ 83,931	$ 190,748	$ 215,188

	Three Months Ended			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	September 30, 2020	September 30, 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	$ 57,997	$ 41,939	$ 68,774	$ 144,419	$ 164,267
Add (Subtract):					
Cash interest payments	14,435	648	14,864	29,962	30,136
Cash income tax payments	221	—	—	222	—
Non-recurring costs	1,473	316	219	3,651	3,061
Other changes in operating assets and liabilities	(12,611)	14,530	74	12,494	17,724
Adjusted EBITDA	$ 61,515	$ 57,433	$ 83,931	$ 190,748	$ 215,188
Subtract:					
Capital expenditures - accrual basis	(5,426)	(16,528)	(63,488)	(61,368)	(169,217)
Interest expense	(8,391)	(8,676)	(8,597)	(25,987)	(26,362)
Cash dividends declared	—	—	(9,720)	(9,564)	(29,502)
Levered Free Cash Flow[(1)]	$ 47,698	$ 32,229	$ 2,126	$ 93,829	$ (9,893)

(1) Levered Free Cash Flow, as defined by the Company, includes cash received for scheduled derivative settlements of $35 million, $52 million and $15 million for the three months ended September 30, 2020, June 30, 2020 and September 30, 2019, respectively. Levered Free Cash Flow, as defined by the Company, includes cash received for scheduled derivative settlements of $107 million and $27 million for the nine months ended September 30, 2020 and 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			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	September 30, 2020	September 30, 2019
			(in thousands)		
Adjusted Net Income (Loss) reconciliation to net (loss) income:					
Net (loss) income	$ (18,864)	$ (64,901)	$ 52,649	$ (199,065)	$ 50,523
Add (Subtract): discrete income tax items	(2,394)	—	—	44,306	—
Add (Subtract):					
(Gains) losses on oil and natural gas derivatives	(4,220)	43,192	(42,501)	(160,222)	2,796
Net cash received for scheduled derivative settlements	35,476	51,874	15,153	106,975	26,731
Other operating expenses (income)	1,648	(1,192)	(550)	2,658	3,814
Impairment of oil and gas properties	—	—	—	289,085	—
Non-recurring costs	1,473	316	219	3,651	3,061
Reorganization items, net	—	—	170	—	426
Total additions, net	34,377	94,190	(27,509)	242,147	36,828
Income tax (expense) benefit of adjustments at effective tax rate[(1)]	333	(24,680)	7,620	(51,152)	(10,164)
Adjusted Net Income	$ 13,452	$ 4,609	$ 32,760	$ 36,236	$ 77,187

(1) Excludes discrete income tax items from the total additions, net line item and the tax effect the discrete income tax items 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			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	September 30, 2020	September 30, 2019
			(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
General and administrative expenses	$ 19,173	$ 18,777	$ 16,434	$ 57,287	$ 46,932
Subtract:					
Non-cash stock compensation expense (G&A portion)	(3,812)	(4,380)	(2,275)	(11,111)	(6,067)
Non-recurring costs	(1,473)	(316)	(219)	(3,651)	(3,061)
Adjusted G&A	$ 13,888	$ 14,081	$ 13,940	$ 42,525	$ 37,804
Adjusted general and administrative expenses ($/MBoe)	$ 5.47	$ 5.31	$ 5.13	$ 5.33	$ 4.90

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 September 30, 2020, we had liquidity of $192 million, consisting of $49 million cash in the bank and borrowing availability of $143 million under our RBL Facility. The RBL Facility currently has a $200 million borrowing base with a $200 million elected commitment and borrowing availability of $150 million until the next semi-annual borrowing base redetermination that is scheduled to occur in November 2020, at which time we expect the availability to return to this elected commitment amount. 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 in 2020 and for the combined two-year down-cycle through the end of 2021, even at the currently depressed commodity price levels, given our current hedge positions and based on our current operating plans. We currently have essentially all of our expected oil production hedged in the fourth quarter of 2020 at nearly $60 per barrel, as well as additional 2021 hedge positions at nearly $46 per barrel for approximately 19,000 Bbls/d in the first half of 2021 and approximately 11,000 Bbls/d in the second half of 2021 at $46 per barrel. As of September 30, 2020, our oil hedge positions had a fair value of approximately $45 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 unknown supply levels caused by OPEC+'s actions, as further discussed under "Business Environment, Market Conditions and Outlook" in this report. Additionally in October 2020, we hedged 12,500 MMBtu/d of our 2021 Rockies gas production at nearly $3.00 per MMBtu.

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 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 the same level of Levered Free Cash Flow we are currently generating and our liquidity and capital resources may not be sufficient to conduct our business and operations in the longer term until commodity prices recover. In light of 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"), we continue to plan for a prolonged downturn and our strategy to survive is focused on preserving cash, reducing costs and maintaining business continuity. We have significantly reduced our initially planned 2020 capital expenditures and non-employee operating and general and administrative expenses and we are focused on achieving additional cost reductions 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. 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 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 ultimately be 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 severity and 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, in the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 of this report. On June 23, 2020, we completed the regular Spring borrowing base redetermination and entered into Limited Waiver and Amendment No. 5 to Credit Agreement (the "Amendment"), with the lenders which, among other changes to the credit agreement described in the Amendment, (1) decreases the borrowing base to $200 million; (2) decreases the elected commitment to $200 million; (3) limits the maximum borrowing availability to $150 million until the next semi-annual borrowing base redetermination which is scheduled to occur in November 2020 at which time we expect the availability to return to this elected commitment amount; (4) implements certain anti-cash hoarding provisions, including the requirement to repay outstanding loans on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $30 million; (5) waives certain events of default arising from the failure to timely deliver certain hedging reports; and (6) further limits dividends and share repurchases. As of September 30, 2020 we had no borrowings outstanding, approximately $7 million in letters of credit outstanding, and approximately $143 million available for borrowing under the RBL Facility. 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.

The RBL Facility contains customary events of default and remedies for credit facilities of a similar nature. 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 September 30, 2020, our Leverage Ratio and Current Ratio were 1.5 to 1.0 and 2.7 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. 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. We were in compliance with all financial covenants under the RBL Facility as of September 30, 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 and gas production to protect against oil and gas price decreases and we also hedge gas purchases to protect against price increases. 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. We expect our operations to generate sufficient cash flows at current commodity prices including our 2020 and 2021 hedging positions. 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 September 30, 2020, we had the following crude oil production and gas purchases hedges.

		Q4 2020		1H 2021		2H 2021
Fixed Price Oil Swaps (Brent):						
Hedged volume (MBbls)		2,208		3,438		2,084
Weighted-average price ($/Bbl)	$	59.85	$	45.82	$	46.17
Purchased Oil Calls Options (Brent):						
Hedged volume (MBbls)		276		—		—
Weighted-average price ($/Bbl)	$	65.00	$	—	$	—
Fixed Price Gas Purchase Swaps (Kern, Delivered):						
Hedged volume (MMBtu)		5,060,000		9,045,000		5,535,000
Weighted-average price ($/MMBtu)	$	2.76	$	2.71	$	2.73
Fixed Price Gas Purchase Swaps (SoCal Citygate):						
Hedged volume (MMBtu)		155,000		—		—
Weighted-average price ($/MMBtu)	$	3.80	$	—	$	—

In October 2020, we added 12,500 MMBtu/d of fixed price gas sales swaps at an average price of $2.96, indexed to Northwest Pipeline Rocky Mountains and CIG, for the period January 1, 2021 through December 31, 2021.

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

	Three Months Ended						Nine Months Ended			
	September 30, 2020		June 30, 2020		September 30, 2019		September 30, 2020		September 30, 2019	
Crude Oil (per Bbl):										
Realized sales price, before the effects of derivative settlements	$	39.88	$	28.98	$	57.92	$	39.00	$	58.79
Effects of derivative settlements	$	16.28	$	25.42	$	7.31	$	16.97	$	4.30
Oil with hedges ($/Bbl)	$	56.16	$	54.40	$	65.23	$	55.97	$	63.09
Purchased Natural Gas (per MMBtu):										
Purchase price, before the effects of derivative settlements	$	2.69	$	1.74	$	2.67	$	2.25	$	3.17
Effects of derivative settlements	$	0.10	$	1.11	$	0.30	$	0.60	$	0.09
Purchased Natural Gas with hedges	$	2.79	$	2.85	$	2.97	$	2.85	$	3.26

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. In April 2020, in connection with the current low oil price environment, we temporarily suspended our quarterly dividend until oil prices recover. As of October 31, 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. 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 repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million as of December 31, 2019. For the nine months ended September 30, 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 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. 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 20% of the then effective borrowing base, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.5 to 1.0. The conditions are currently met with significant margin.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Nine Months Ended September 30,	
	2020	**2019**
	(in thousands)	
Net cash:		
Provided by operating activities	$ 144,419	$ 164,267
Used in investing activities	(74,522)	(176,138)
Used in financing activities	(22,277)	(56,809)
Net increase (decrease) in cash and cash equivalents	$ 47,620	$ (68,680)

Operating Activities

Cash provided by operating activities decreased for the nine months ended September 30, 2020 by approximately $20 million when compared to the nine months ended September 30, 2019, due to decreased sales of $129 million, and increased general and administrative expenses of $6 million. These decreases were partially offset by increased derivatives settlements received of $80 million, decreased lease operating expenses and electricity generation expenses of $24 million, decreased taxes, other than income taxes of $4 million, and working capital changes of $7 million.

Investing Activities

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

	Nine Months Ended September 30, 2020	2019
	(in thousands)	
Capital expenditures:[1]		
Development of oil and natural gas properties	$ (58,370)	$ (157,281)
Purchase of other property and equipment	(3,951)	(12,394)
Changes in capital investment accruals	(10,347)	(4,613)
Acquisition of properties and equipment and other	(2,104)	(2,819)
Proceeds from sale of properties and equipment and other	250	969
Cash used in investing activities	$ (74,522)	$ (176,138)

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

Cash used in investing activities decreased $102 million for the nine months ended September 30, 2020 when compared to the same period in 2019, primarily due to a decrease in capital spending in accordance with the revised 2020 capital budget.

Financing Activities

Cash used by financing activities was approximately $22 million for the nine months ended September 30, 2020 and decreased by approximately $35 million from the nine months ended September 30, 2019. The decrease is largely due to treasury stock purchases of $36 million in the nine months ended September 30, 2019 and none in the nine months ended September 30, 2020. Additionally, we paid fewer dividends in 2020 by approximately $10 million. Partially offsetting the positive cash impact of these activities, we reduced our net borrowings by approximately $12 million on the RBL Facility in 2020 compared to 2019.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2019 to September 30, 2020 are discussed below.

	September 30, 2020		December 31, 2019	
	(in thousands)			
Cash and cash equivalents	$	47,620	$	—
Accounts receivable, net	$	48,798	$	71,867
Derivative instruments assets - current and long-term	$	59,669	$	9,691
Other current assets	$	20,318	$	19,399
Property, plant & equipment, net	$	1,260,755	$	1,576,267
Other non-current assets	$	9,297	$	12,974
Accounts payable and accrued liabilities	$	95,237	$	151,811
Derivative instruments liabilities - current and long-term	$	1,516	$	4,958
Long-term debt	$	393,219	$	394,319
Deferred income taxes liability - long-term	$	9,318	$	9,057
Asset retirement obligation - long-term	$	136,392	$	124,019
Other non-current liabilities	$	36,150	$	33,586
Equity	$	774,625	$	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, both price and volume period-over-period, partially offset by higher hedge settlements at each period-end.

The $53 million increase in derivative assets and liabilities reflected the net appreciation in the mark-to-market values of the derivatives, lower forward curve prices relative to the contract fixed price, 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 $316 million decrease in property, plant and equipment was largely the result of the $289 million impairment on our oil and gas properties in the first quarter of 2020, as well as depreciation expense of $101 million, partially offset by capital investments of $61 million, $6 million of acquisitions and capitalized interest and $6 million for asset retirement obligations.

The $4 million decrease in other non-current assets is mainly due to deferred debt issuance cost amortization.

The $57 million decrease in accounts payable and accrued liabilities included approximately $21 million of decreased accruals and spending for various capital and operating costs due to the reduced level of these costs in 2020, $13 million fewer royalties accrued due to decreased sales, $12 million reclassified from current to long-term portion of the asset retirement obligation based on budgeted spending and regulatory requirements, and the $10 million impact of dividends accrued at the end of 2019 with no corresponding accrual at September 30, 2020.

The increase in long-term deferred income taxes liability is due to the income tax expense and change in current portion due during the period.

The $12 million increase in the long-term portion of the asset retirement obligation from $124 million at December 31, 2019 to $136 million at September 30, 2020 was due to $7 million of accretion, $6 million of liabilities incurred and $12 million of reclassification from the current portion due to changes in budgeted spending and regulatory requirements. These increases were partially offset by $12 million of liabilities settled during the period.

The increase in other non-current liabilities was driven by higher greenhouse gas liabilities as a result of periodic emissions and slight price increases. This liability is due for payment more than one year from September 30, 2020.

The decrease in equity of $198 million was due to net loss of $199 million and $10 million of common stock dividends declared. These decreases were partially offset by $11 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 the subject of, or party to, pending or threatened legal proceedings, contingencies and commitments involving a variety of matters that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, fines and penalties, remediation costs, 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 September 30, 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 September 30, 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. Prior to our 2017 emergence, Berry entered into a Carry and Earning Agreement with Encana, effective June 7, 2006, in connection with our Piceance assets which, among other things, required us 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. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We will 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 September 30, 2020:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Debt obligations:					
RBL Facility	$ —	$ —	$ —	$ —	$ —
2026 Notes	400,000	—	—	—	400,000
Interest(1)	150,529	28,000	56,000	56,000	10,529
Other:					
Asset retirement obligations(2)	150,092	13,700	—	—	136,392
Off-Balance Sheet arrangements:					
Processing, transportation and storage contracts(3)	9,822	5,350	4,472	—	—
Operating lease obligations	11,552	1,848	3,724	3,100	2,880
Other purchase obligations(4)	35,100	18,000	17,100	—	—
Total contractual obligations	$ 757,095	$ 66,898	$ 81,296	$ 59,100	$ 549,801

(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, processing and storage 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 December 31, 2019, we fulfilled the obligation by delivering the access license pursuant to the agreement. On January 30, 2020, Caerus Piceance LLC, the successor of Encana's interests filed a claim in the City and County of Denver District Court challenging the sufficiency of such access, which we dispute. We will 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. We currently have a drilling commitment in which we are required to drill 97 wells with an estimated total cost of $29 million by August 2022 and 40 of those wells are required to be drilled by July 2021.

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 ongoing 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 foreign producers, importantly including OPEC+ 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 second quarter of 2020;
- 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;
- 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;
- 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 September 30, 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 September 30, 2020, the fair value of our hedge positions was a net asset of approximately $58 million. A 10% increase in the oil and natural gas index prices above the September 30, 2020 prices would result in a decrease in the net asset to approximately $42 million; conversely, a 10% decrease in the oil and natural gas index prices below the September 30, 2020 prices would result in an increase in the net asset to approximately $99 million. For additional information about derivative activity, see Note 3, Derivatives, in the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 of this report.

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 September 30, 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 September 30, 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 September 30, 2020, we had no 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, Debt, in the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 of this report 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 September 30, 2020.

There were no changes in the Company’s internal control over financial reporting during the third 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 impact our financial and operational results, include the following:

Attempts by several states to restrict the production of oil and gas could negatively impact our operations and result in decreased demand for fossil fuels within the state.

Recently, California and Colorado, have taken several actions that could adversely impact oil and gas production in those states. On September 23, 2020, Governor Gavin Newsom of California issued an executive order (the "Order") that seeks to reduce both the supply of and demand for fossil fuels in the state. The Order establishes several goals and directs several state agencies to take certain actions with respect to reducing emissions of greenhouse gases, including, but not limited to: phasing out the sale of emissions-producing vehicles; developing strategies for the closure and repurposing of oil & gas facilities in California; and ending the issuance of new hydraulic fracturing permits in the state by 2024. The Order also directs CalGEM to finish its review of public health and safety concerns from the impacts of oil extraction activities and propose significantly strengthened regulations, which may include setbacks, to address these concerns by December 31, 2020. Any of these developments may adversely impact both demand for our products or production from our properties.

While the Order does not impose a ban on the issuance of hydraulic fracturing permits, Governor Newsom has announced plans to ask the legislature to pass legislation to this effect. While several California legislators have already indicated that they intend to propose such a ban, the ultimate outcome of any proposed legislation remains uncertain at this time, as past measures to further impose additional stringent requirements upon oil and gas activities in the California legislature were not successful. For example, in both 2019 and 2020, California considered legislation to impose a statewide setback distance between certain oil and natural gas operations and residences, schools, and healthcare facilities. However, in both cases, the proposal failed to receive the approval of the California State Senate.

Separately, in September 2020, the Colorado Oil and Gas Conservation Commission (“COGCC”) announced that it will consider imposing a 2,000-foot setback requirement for drilling and fracking operations statewide, allowing for variances subject to certain conditions. The vote on this rulemaking is expected to take place at the COGCC’s November 6, 2020 meeting. While we cannot predict the final outcome of the COGCC’s actions, any regulation restricting the siting of oil and gas facilities or otherwise imposing more stringent operating controls may adversely impact production from our properties.

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 resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. This resulted in 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 August 1, 2020.

In mid-April 2020, members of OPEC+ agreed to certain production cuts; however, these cuts only slightly offset the significant decrease in demand resulting from the COVID-19 pandemic and related economic repercussions. During the second quarter of 2020, the price of Brent crude oil reached historic low of just under $20 per barrel. Although pricing has strengthened slightly, it is still lower than pre-pandemic levels and the current futures forward curve for Brent crude indicates that prices are expected to continue at low levels for an extended time. As of November 1, 2020, the benchmark Brent oil price was $37.46 per barrel as compared to the average benchmark Brent oil price of $63.15 per barrel used to determine our 2019 year end reserves based on SEC pricing.

Additionally, although the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics. During the second quarter of 2020, we experienced an adverse widening in the price differential between Brent and California crude due to the lack of local demand and storage capacity. This differential widening improved in the third quarter 2020 as the market storage concerns began to soften, however, if California pricing remains weak, or declines, 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%, which negatively impacted production during the second and third quarters 2020 and may negatively impact future production levels due to the natural production decline of our assets. This, combined with expected lower commodity prices, could materially adversely affect our cash flows and the quantity and value of estimated proved reserves that may be attributed to our properties. A persistent price decline could adversely affect the economics of our existing wells and planned future wells, 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 several months, most of our personnel worked remotely and many of our key vendors, service suppliers and partners have been as well. Although we managed the transition to temporary work from home arrangements and subsequent office re-openings without a significant loss in business continuity, we incurred additional costs and experienced some inefficiencies during the second and third quarters 2020 as a result. If the ongoing outbreak were to worsen, and additional restrictions be implemented, we may again have to consider remote work arrangements, and certain operational and other business 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 beginning in the first quarter of 2020 and prices have remained weak and below pre-pandemic levels. 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. Historically, when the U.S. and global economies experience weakness, demand for energy has declined. 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 coupled with the increase in supply from the actions of OPEC+. On June 6, 2020, members of OPEC+ agreed to certain production cuts, which slightly offset the decrease in demand resulting from the COVID-19 pandemic. In August 2020, these production cuts were eased slightly and the current output reduction levels are expected to remain through the end of the year.

During the second and third quarters 2020, oil prices recovered slightly from the historical low levels at the beginning of the second quarter as global demand began to increase gradually with containment of the COVID-19 outbreak in areas around the globe and the supply surge was curtailed as members of OPEC+ agreed to certain production cuts. This recovery appears fragile and has flattened, with oil price volatility remaining elevated and oil demand remaining below pre-COVID-19 pandemic levels. Demand, and pricing, may again decline due to the ongoing COVID-19 pandemic, particularly if there is a resurgence of the outbreak during the latter part of the year as some are predicting, although the extent of the additional impact on our industry and our business cannot be reasonably predicted at this time. If storage availability also becomes further constrained, 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.

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 fell during the second quarter 2020, we experienced an adverse widening in the price differential between Brent and the California benchmark due to the lack of local demand and storage capacity. Although market conditions improved and the differential widening softened toward the end of the second quarter 2020, if California pricing remains weak, or declines, our financial and operating results will be 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 limited and may become completely unavailable in the near future. Storage became scarce during the second quarter of 2020 due to the unprecedented dual impact of a severe global oil demand decline coupled with a substantial increase in supply. As traditional tanks filled, large quantities of oil were being stored in offshore tankers around the world, including off the coast of California. Where storage was available, such as offshore tankers, storage costs increased sharply. If the imbalance between supply and demand and the related shortage of storage capacity worsen, the prices we receive for our production could deteriorate and could potentially even become negative as WTI oil prices did on April 20, 2020.

During the second quarter of 2020, we obtained additional storage capacity to support our planned production for the remainder of the year and into 2021. As market conditions improved, we released a portion of the capacity. However, the risk remains that storage for oil may be unavailable and our existing capacity may be insufficient to support planned production rates in the event of demand for our oil deteriorating again or a supply surge or both. If we are unable to obtain additional storage capacity if needed, 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 additional 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 face 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 (subject to change each quarter; as of December 31, 2019 estimated U.S. federal and state NOL carryforwards of approximately $122 million and $42 million, respectively, and U.S. federal general business credits of approximately $48 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 2018 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. 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 repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million as of December 31, 2019. For the nine months ended September 30, 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	Employment Agreement by and between Berry Petroleum Company, LLC and Fernandez Araujo, effective August 14, 2020 (incorporated by reference to Exhibit 10.1 of Form 8-K filed August 20, 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
101.INS*	Inline XBRL Instance Document (the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE*	Inline 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.

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

"*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:	November 4, 2020	/s/ Cary Baetz Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	November 4, 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: November 4, 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: November 4, 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 September 30, 2020, as filed with the Securities and Exchange Commission on November 4, 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:	November 4, 2020	/s/ A. T. Smith
		A. T. "Trem" Smith
		President and Chief Executive Officer

Date:	November 4, 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.