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, 2021
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 Exchange Act). Yes ☐ No ☒

Shares of common stock outstanding as of October 31, 2021 80,007,149

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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, 2021	December 31, 2020
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 38,161	$ 80,557
Accounts receivable, net of allowance for doubtful accounts of $1,715 at September 30, 2021 and $2,215 at December 31, 2020	69,315	52,027
Derivative instruments	884	2,507
Other current assets	70,559	19,400
Total current assets	178,919	154,491
Noncurrent assets:		
Oil and natural gas properties	1,483,389	1,412,566
Accumulated depletion and amortization	(309,089)	(235,259)
Total oil and natural gas properties, net	1,174,300	1,177,307
Other property and equipment	91,052	112,145
Accumulated depreciation	(32,129)	(31,368)
Total other property and equipment, net	58,923	80,777
Derivative instruments	2,042	—
Other noncurrent assets	15,782	7,235
Total assets	$ 1,429,966	$ 1,419,810
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 154,591	$ 151,985
Derivative instruments	39,467	23,321
Total current liabilities	194,058	175,306
Noncurrent liabilities:		
Long-term debt	394,285	393,480
Derivative instruments	15,603	—
Deferred income taxes	—	1,011
Asset retirement obligations	115,458	135,192
Other noncurrent liabilities	25,666	785
Commitments and Contingencies - Note 4		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 85,590,417 and 85,041,581 shares issued; and 80,007,149 and 79,929,335 shares outstanding, at September 30, 2021 and December 31, 2020, respectively)	86	85
Additional paid-in-capital	913,544	915,877
Treasury stock, at cost (5,583,268 and 5,112,246 shares at September 30, 2021 and December 31, 2020, respectively)	(52,436)	(49,995)
Retained deficit	(176,298)	(151,931)
Total stockholders' equity	684,896	714,036
Total liabilities and stockholders' equity	$ 1,429,966	$ 1,419,810

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,	
	2021	2020	2021	2020
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 161,058	$ 92,239	$ 444,098	$ 284,852
Electricity sales	12,371	8,744	29,328	19,089
(Losses) gains on oil and gas sales derivatives	(30,864)	(11,564)	(140,021)	157,398
Marketing revenues	732	330	3,087	1,075
Other revenues	117	—	372	53
Total revenues and other	143,414	89,749	336,864	462,467
Expenses and other:				
Lease operating expenses	60,930	45,243	168,756	136,727
Electricity generation expenses	7,128	4,217	19,488	11,186
Transportation expenses	1,806	1,768	5,139	5,379
Marketing expenses	715	326	2,986	1,036
General and administrative expenses	17,614	19,173	50,749	57,287
Depreciation, depletion, and amortization	35,902	35,905	105,592	108,746
Impairment of oil and gas properties	—	—	—	289,085
Taxes, other than income taxes	13,420	9,913	34,580	24,714
Gains on natural gas purchase derivatives	(14,980)	(15,784)	(54,349)	(2,824)
Other operating expenses	3,986	1,648	4,827	2,658
Total expenses and other	126,521	102,409	337,768	633,994
Other (expenses) income:				
Interest expense	(7,810)	(8,391)	(24,513)	(25,987)
Other, net	(5)	(3)	(156)	(15)
Total other (expenses) income	(7,815)	(8,394)	(24,669)	(26,002)
Income (loss) before income taxes	9,078	(21,054)	(25,573)	(197,529)
Income tax (benefit) expense	(758)	(2,190)	(1,206)	1,536
Net income (loss)	$ 9,836	$ (18,864)	$ (24,367)	$ (199,065)
Net income (loss) per share:				
Basic	$ 0.12	$ (0.24)	$ (0.30)	$ (2.50)
Diluted	$ 0.12	$ (0.24)	$ (0.30)	$ (2.50)

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

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

	Nine-Month Period Ended September 30, 2020				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Deficit	Total Stockholders' 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

	Nine-Month Period Ended September 30, 2021				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Deficit	Total Stockholders' Equity
	(in thousands)				
December 31, 2020	$ 85	$ 915,877	$ (49,995)	$ (151,931)	$ 714,036
Shares withheld for payment of taxes on equity awards and other	—	(1,442)	—	—	(1,442)
Stock based compensation	—	3,995	—	—	3,995
Issuance of common stock	1	—	—	—	1
Dividends declared on common stock, $0.04/share	—	(3,474)	—	—	(3,474)
Net loss	—	—	—	(21,322)	(21,322)
March 31, 2021	86	914,956	(49,995)	(173,253)	691,794
Shares withheld for payment of taxes on equity awards and other	—	(78)	—	—	(78)
Stock based compensation	—	3,042	—	—	3,042
Dividends declared on common stock, $0.04/share	—	(3,219)	—	—	(3,219)
Net loss	—	—	—	(12,881)	(12,881)
June 30, 2021	86	914,701	(49,995)	(186,134)	678,658
Shares withheld for payment of taxes on equity awards and other	—	(23)	—	—	(23)
Stock based compensation	—	3,672	—	—	3,672
Purchases of treasury stock	—	—	(2,441)	—	(2,441)
Dividends declared on common stock, $0.06/share	—	(4,806)	—	—	(4,806)
Net income	—	—	—	9,836	9,836
September 30, 2021	$ 86	$ 913,544	$ (52,436)	$ (176,298)	$ 684,896

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, 2021	Nine Months Ended September 30, 2020
	(in thousands)	
Cash flows from operating activities:		
Net loss	$ (24,367)	$ (199,065)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	105,592	108,746
Amortization of debt issuance costs	3,839	3,990
Impairment of oil and gas properties	—	289,085
Stock-based compensation expense	10,219	11,397
Deferred income taxes	(1,231)	(702)
(Decrease) increase in allowance for doubtful accounts	(500)	1,112
Other operating expenses	3,988	2,145
Derivative activities:		
Total losses (gains)	85,672	(160,222)
Cash settlements on derivatives	(54,204)	106,975
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(16,760)	21,985
(Increase) decrease in other assets	(19,062)	(919)
(Decrease) increase in accounts payable and accrued expenses	(11,343)	(29,882)
Increase (Decrease) in other liabilities	415	(10,226)
Net cash provided by operating activities	82,258	144,419
Cash flows from investing activities:		
Capital expenditures:		
Capital expenditures	(105,046)	(62,321)
Changes in capital expenditures accruals	5,299	(10,347)
Acquisition of properties and equipment and other	(11,649)	(2,104)
Proceeds from sale of property and equipment and other	860	250
Net cash used in investing activities	(110,536)	(74,522)
Cash flows from financing activities:		
Borrowings under 2017 RBL credit facility	—	228,900
Repayments on 2017 RBL credit facility	—	(230,750)
Dividends paid on common stock	(6,686)	(19,447)
Purchase of treasury stock	(2,440)	—
Shares withheld for payment of taxes on equity awards and other	(1,543)	(980)
Debt issuance costs	(3,449)	—
Net cash used in financing activities	(14,118)	(22,277)
Net (decrease) increase in cash and cash equivalents	(42,396)	47,620
Cash and cash equivalents:		
Beginning	80,557	—
Ending	$ 38,161	$ 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 each of its three Delaware limited liability company subsidiaries: (1) Berry Petroleum Company, LLC ("Berry LLC"), (2) CJ Berry Well Services Management, LLC ("C&J Management") and (3) C&J Well Services, LLC ("C&J Well Services").

As the context may require, the "Company", "we", "our" or similar words refer to (i) for periods prior to October 1, 2021, (a) Berry Corp. and its consolidated subsidiary, Berry LLC, as a whole or (b) either Berry Corp. or Berry LLC, and (ii) for periods on or after October 1, 2021, (a) Berry Corp. and its consolidated subsidiaries, as a whole, or (b) either Berry Corp., Berry LLC, C&J Management or C&J Well Services.

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 three wholly owned subsidiaries. Berry LLC owns and operates our oil and gas assets, all of which are located onshore in the United States (the "U.S."), in California (primarily in the San Joaquin basin), Utah (in the Uinta basin), and Colorado (in the Piceance basin). We are focused on the development and production of onshore, low geologic risk, long-lived conventional oil reserves.

Effective as of October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California (the "C&J Well Services Acquisition"). This business is owned and operated through C&J Well Services.

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, 2020.

The financial results of C&J Well Services, the business of which we acquired on October 1, 2021, are not included in the third quarter unaudited condensed consolidated financial statements, but will be included beginning in the fourth quarter of 2021 (see Note 9).

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.

Recently Adopted Accounting Standards

In December 2019, the FASB issued rules which simplify the accounting for income taxes. We adopted these rules in the first quarter of 2021 which did not have a material impact on our financial statements.

Note 2—Debt

The following table summarizes our outstanding debt:

	September 30, 2021	December 31, 2020	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ —	n/a	variable rates 5.3% (2021)	August 26, 2025	Mortgage on 90% of Present Value of proven oil and gas reserves and lien on certain other assets
2017 RBL Facility	n/a	$ —	variable rates 4.0% (2020)	July 29, 2022 (Terminated August 26, 2021)	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	400,000			
Less: Debt Issuance Costs	(5,715)	(6,520)			
Long-Term Debt, net	$ 394,285	$ 393,480			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At September 30, 2021 and December 31, 2020, debt issuance costs for the 2021 RBL Facility and 2017 RBL Facility (each as defined below) reported in “other noncurrent assets” on the balance sheet were approximately $5 million and $7 million net of amortization, respectively. In the third quarter of 2021 we expensed $3 million of unamortized debt issuance costs related to the termination of the 2017 RBL Facility. Also in the third quarter of 2021 we incurred approximately $3 million of legal and bank fees related to the issuance of the 2021 RBL Facility, which costs are reported in “other noncurrent assets” on the balance sheet. At September 30, 2021 and December 31, 2020, debt issuance costs, net of amortization, for the unsecured notes due February 2026 (the “2026 Notes”) reported in “Long-Term Debt, net” on the balance sheet were approximately $6 million and $7 million, respectively.

For each of the three month periods ended September 30, 2021 and 2020, the amortization expense for the 2021 RBL Facility, the 2017 RBL Facility and the 2026 Notes, combined, 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, 2021 and 2020, the amortization expense for the 2021 RBL Facility, the 2017 RBL Facility and the 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 2021 RBL Facility approximates fair value because the interest rates are variable and reflect market rates. The fair value of the 2026 Notes was approximately $409 million and $337 million at September 30, 2021 and December 31, 2020, respectively.

2021 RBL Facility

On August 26, 2021, we entered into a credit agreement that provided for a revolving loan with up to $500 million of commitment, subject to a reserve borrowing base ("2021 RBL Facility"). Our initial borrowing base and elected commitment is $200 million. The 2021 RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $20 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the 2021 RBL Facility on a dollar for dollar basis. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. Borrowing base redeterminations generally become effective each May and November, although the borrower and the lenders may each make one interim redetermination between scheduled redeterminations. The first scheduled redetermination is scheduled for November 2021.

If the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base at any time as a result of a redetermination of the borrowing base, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, deliver reserve engineering reports and mortgages covering additional oil and gas properties sufficient in certain lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the next six-month period. Upon certain adjustments to the borrowing base, we are required to make a lump sum payment in an amount equal to the amount by which the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base. In addition, the 2021 RBL Facility provides that if there are any outstanding borrowings and the consolidated cash balance exceeds $20 million at the end of each calendar week, such excess amounts shall be used to prepay borrowings under the credit agreement. Otherwise, any unpaid principal will be due at maturity.

The outstanding borrowings under the revolving loan bear interest at a rate equal to either (i) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% per annum, and (ii) a customary benchmark rate plus an applicable margin ranging from 3.0% to 4.0% per annum, and in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.5% on the average daily unused amount of the borrowing availability under the 2021 RBL Facility. We have the right to prepay any borrowings under the 2021 RBL Facility with prior notice at any time without a prepayment penalty.

The 2021 RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a leverage ratio of not more than 3.0 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of September 30, 2021, our leverage ratio and current ratio were 2.1:1.0 and 2.4:1.0, respectively. In addition, the 2021 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 2021 RBL Facility as of September 30, 2021.

The 2021 RBL Facility contains usual and customary events of default and remedies for credit facilities of a similar nature. The 2021 RBL Facility also places restrictions on the borrower and its restricted subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of the borrower's senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters. For instance, the 2021 RBL Facility contains certain oil sales hedging requirements.

The 2021 RBL Facility permits us to repurchase equity and indebtedness, among other things, if availability is equal to or greater than 20% of the elected commitments or borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

Berry Corp. and its existing subsidiaries (other than Berry LLC (who is the borrower), C&J Management and C&J Well Services) guarantee, and each future subsidiary of Berry Corp., with certain exceptions, is required to guarantee, our obligations and obligations of the other guarantors under the 2021 RBL Facility and under certain hedging transactions and banking services arrangements (the "Guaranteed Obligations"). The lenders under the 2021

RBL Facility hold a mortgage on at least 90% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions.

As of September 30, 2021, we had no borrowings outstanding and approximately $200 million of available borrowings capacity under the 2021 RBL Facility.

2017 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 ("2017 RBL Facility"). In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our 2017 RBL Facility, which resulted in a reaffirmed borrowing base and our elected commitment at $200 million. On August 26, 2021, we terminated the 2017 RBL Facility agreement. There were no borrowings outstanding at the time of termination.

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 do 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 and is subject to a passive holding company covenant under the 2021 RBL Facility. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. 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 restrictions under the 2021 RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

The 2021 RBL Facility permits Berry Corp. to make dividends so long as both before and after giving pro forma effect to such distribution, no default or event of defaults exists, availability exceeds 20% of the elected commitments or borrowing base, whichever is in effect, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.0 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. In addition to the hedging requirements of the 2021 RBL Facility, we target covering our operating expenses and a majority of our fixed charges, which includes capital needed to sustain production levels, as well as interest and fixed dividends as applicable, with the oil and gas sales hedges for a period of up to three 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 have also entered into Utah gas transportation contracts to help reduce the price fluctuation exposure, however these do not qualify as hedges. 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 puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For some of our purchased puts we paid a premium at the time the positions were created and for others, the premium payment is deferred until the time of settlement. As of September 30, 2021 we have offsetting put positions with an outstanding deferred premium of approximately $24 million, which is reflected in the mark-to-market valuation and will be payable beginning in 2022 through 2024, in approximately the same amount each year.

For our sold oil and gas puts, we would make settlement payments for prices below the indicated weighted-average price. No payment would be due for prices above the indicated weighted-average price.

For our sold oil and gas calls, we would make settlement payments for prices above the indicated weighted-average price. No payment would be due for prices below the indicated weighted-average price.

For our purchased gas calls, we would receive settlement payment for prices above the indicated weighted-average price. No payment would be received for prices below the indicated weighted-average price.

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, 2021, we had the following crude oil production and gas purchase hedges.

	Q4 2021	FY 2022	FY 2023	FY 2024
Fixed Price Oil Swaps (Brent):				
Hedged volume (mbbls)	1,318	3,387	1,596	732
Weighted-average price ($/bbl)	$ 48.61	$ 66.63	$ 65.26	$ 61.78
Purchased Oil Put Options (Brent):				
Hedged volume (mbbls)	307	1,643	2,555	1,647
Weighted-average price ($/bbl)	$ 60.00	$ 50.00	$ 50.00	$ 50.00
Sold Oil Put Options (Brent):				
Hedged volume (mbbls)	—	1,643	2,555	1,647
Weighted-average price ($/bbl)	$ —	$ 40.00	$ 40.00	$ 40.00
Sold Oil Calls Options (Brent):				
Hedged volume (mbbls)	307	—	—	—
Weighted-average price ($/bbl)	$ 75.00	$ —	$ —	$ —
Purchased Gas Call Options (Henry Hub):				
Hedged volume (mmbtu)	1,830,000	10,950,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 4.00	$ 4.00	$ 4.00	$ 4.00
Sold Gas Put Options (Henry Hub):				
Hedged volume (mmbtu)	1,830,000	10,950,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 2.75	$ 2.75	$ 2.75	$ 2.75
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (mmbtu)	2,085,000	—	—	—
Weighted-average price ($/mmbtu)	$ 2.95	$ —	$ —	$ —

As of September 30, 2021 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 mmbtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period October 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of approximately $1 million. This gain will be cash settled in 2021 as the positions expire.

In October we added purchased gas put options (Henry Hub) of 20,000 mmbtu/d at $2.75 beginning November 2021 through March 2022, which offset the fourth quarter 2021 and first quarter 2022 sold gas put options included in the above table. We added sold oil put options (Brent) of 500 bbl/d at $60.00 beginning November 2021 through December 2021, which offset the fourth quarter 2021 purchased oil put options included in the above table. We also added purchased fixed price oil swaps (Brent) of 1,000 bbl/d at $66.95 beginning January 2022 through December 2022, which partially offset the 2022 fixed price oil swaps included in the table above.

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, 2021 and December 31, 2020:

	September 30, 2021			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Assets:				
Commodity Contracts	Current assets	$ 30,356	$ (29,472)	$ 884
Commodity Contracts	Non-current assets	36,287	(34,245)	2,042
Liabilities:				
Commodity Contracts	Current liabilities	(68,939)	29,472	(39,467)
Commodity Contracts	Non-current liabilities	(49,848)	34,245	(15,603)
Total derivatives		$ (52,144)	$ —	$ (52,144)

	December 31, 2020			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Assets:				
Commodity Contracts	Current assets	$ 15,217	$ (12,710)	$ 2,507
Liabilities:				
Commodity Contracts	Current liabilities	(36,031)	12,710	(23,321)
Total derivatives		$ (20,814)	$ —	$ (20,814)

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 2021 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 A2 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 subsidiaries, 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 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, 2021 and December 31, 2020. 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 accruals on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiaries, 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, 2021, 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 continue to defend the matter vigorously, however, given the uncertainty of litigation and the stage of the case, among other things, at this time we cannot estimate the likelihood or an amount of possible loss, that may result from this action.

During the second and third quarters of 2021 we entered into pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California, that will reduce our exposure to fuel gas purchase price fluctuations. During the third quarter of 2021 we entered into a capacity agreement for approximately 32,700 mmbtu/d beginning May 2022 through April 2032 for a total commitment of $62 million. In the second quarter of 2021 we entered into pipeline capacity agreements for approximately 10,000 mmbtu/d beginning October 2021 through October 2036 and approximately 5,500 mmbtu/d beginning November 2021 through December 2024 for a total commitment of $32 million. The average price for all three agreements is approximately $0.52 mmbtu/d.

Securities Litigation Matter

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (the “Defendants”). The complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company’s business, operational efficiency and stability, and compliance policies, that artificially inflated the Company’s stock price, resulting in injury to the purported class members when the value of Berry Corp.’s common stock declined following release of its financial results for the third quarter of 2020.

On January 21, 2021, motions were filed in the Torres Lawsuit as plaintiffs sought to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, alleging, among other things, that the Company and the individual defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company’s permits and permitting processes. The amended complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys’ fees and costs. The defendants’ motion to dismiss the amended complaint is due January 10, 2022. All briefing on the motion to dismiss will be completed by May 2, 2022, and no oral argument has yet been scheduled.

We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Note 5—Equity

Cash Dividends

Our Board of Directors approved a regular cash dividend of $0.04 per share on our common stock for each of the first and second quarters of 2021. We paid the first and the second quarter cash dividend in April and July 2021, respectively. The Board of Directors approved a $0.06 per share regular cash dividend on our common stock for each of the third and fourth quarters of 2021. We paid the third quarter dividend in October 2021 and the fourth quarter dividend is expected to be paid in January 2022.

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 the time, they authorized repurchases of up to $50 million under the program. In 2018 and 2019, the Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in aggregate. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million available under the repurchase program. We did not repurchase any common stock in 2020. For the three and nine months ended September 30, 2021, we repurchased 471,022 shares at an average price of $5.18 per share for approximately $2 million, which is reflected as treasury stock. Accordingly, as of September 30, 2021, the Company has repurchased a total of 5,528,704 shares under the stock repurchase program for approximately $52 million in aggregate, leaving approximately $48 million authorized and available for future repurchases under the 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.

Stock-Based Compensation

In February 2021, the Company granted awards of 1,832,941 shares of restricted stock units ("RSUs"), which will vest annually in equal amounts over three years and 997,840 performance-based restricted stock units ("PSUs"), which will cliff vest, if at all, at the end of a three year performance period. The fair value of these awards was approximately $14 million.

The RSUs awarded in February 2021 are solely time-based awards. Of the PSUs awarded in February 2021, (a) 50% of such will vest, if at all, based on a total stockholder return ("TSR") performance metric (the "TSR PSUs"), which is defined as the capital gains per share of stock plus dividends paid assuming reinvestment, with TSR measured on an absolute basis and relative to the TSR of the 39 exploration and production companies in the Vanguard World Fund - Vanguard Energy ETF Index plus the S&P SmallCap 600 Value Index (collectively, the "Peer Group") during the performance period; and (b) the other 50% of such will vest, if at all, based on the Company's average cash returned on invested capital ("CROIC PSUs") over the performance period. 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 250% of the TSR PSUs granted and from 0% to 200% of the CROIC PSUs granted.

The fair value of the RSUs and CROIC PSUs was determined using the grant date stock price. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the Peer Group 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, 2021	December 31, 2020
	(in thousands)	
Assets held for sale	$ 32,326	$ —
Prepaid expenses	25,024	3,592
Materials and supplies	9,711	11,666
Oil inventories	3,272	3,490
Other	226	652
Total other current assets	$ 70,559	$ 19,400

Other non-current assets at September 30, 2021, included approximately $10.4 million of costs in escrow for the C&J Acquisition (see Note 9) and $5 million of deferred financing costs, net of amortization. At December 31, 2020, other non-current assets included approximately $7 million of deferred financing costs, net of amortization.

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

	September 30, 2021	December 31, 2020
	(in thousands)	
Accounts payable-trade	$ 11,762	$ 11,055
Accrued expenses	58,095	43,452
Royalties payable	20,469	15,150
Greenhouse gas liability - current portion	—	35,554
Taxes other than income tax liability	14,671	10,118
Accrued interest	3,597	10,783
Dividends payable	4,803	—
Asset retirement obligations - current portion	20,000	25,000
Liabilities related to assets held for sale	20,428	—
Other	766	873
Total accounts payable and accrued expenses	$ 154,591	$ 151,985

The decrease of $20 million in the long-term portion of the asset retirement obligations from $135 million at December 31, 2020 to $115 million at September 30, 2021 was due to a $20 million reclassification of long-term to current liabilities related to assets held for sale, $12 million of liabilities settled during the period, and a $2 million reduction related to property sales. These decreases were offset by $8 million of accretion, a $5 million change from short-term to long-term liabilities due to changes in anticipated spending and $1 million of liabilities incurred.

Other non-current liabilities at September 30, 2021 included approximately $25 million greenhouse gas liability.

Supplemental Information on the Statement of Operations

For the three months ended September 30, 2021, other operating expenses was $4 million and mainly consisted of expensing $3 million of unamortized debt issuance costs related to the termination of the 2017 RBL Facility. For the three months ended September 30, 2020, other operating expenses was $2 million and mainly consisted of excess abandonment costs and oil tank storage fees.

For the nine months ended September 30, 2021 and 2020, other operating expenses were $5 million and $3 million, respectively. For the nine months ended September 30, 2021, other operating expenses mainly consisted of expensing $3 million of unamortized debt issuance costs related to the termination of the 2017 RBL Facility, approximately $3 million of supplemental property tax assessments, royalty audit charges and tank rental costs and $1 million of various other costs such as abandonment costs and legal fees, partially offset by $2 million of income from employee retention credits. For the nine months ended September 30, 2020, other operating expenses included $2 million of excess abandonment costs, $1 million of oil tank storage fees, and $1 million of drilling rig standby charges, partially offset by $1 million of taxes and other refunds.

Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
	2021	2020
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 2,916	$ 1,013
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 29,114	$ 29,962
Income taxes payments	$ 294	$ 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 none as of September 30, 2021 and approximately $2 million as of December 31, 2020.

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 months ended September 30, 2021, 2,656,000 incremental RSU and PSU shares were included in the diluted EPS calculation, as their effect was dilutive under the “if converted” method. For the three months ended September 30, 2020 and the nine months ended September 30, 2021 and 2020, no incremental RSUs or PSUs were included in the diluted EPS calculation as their effect was anti-dilutive under the “if converted” method.

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in thousands except per share amounts)			
Basic EPS calculation				
Net income (loss)	$ 9,836	$ (18,864)	$ (24,367)	$ (199,065)
Weighted-average shares of common stock outstanding	80,242	79,879	80,277	79,776
Basic income (loss) per share	$ 0.12	$ (0.24)	$ (0.30)	$ (2.50)
Diluted EPS calculation				
Net income (loss)	$ 9,836	$ (18,864)	$ (24,367)	$ (199,065)
Weighted-average shares of common stock outstanding	80,242	79,879	80,277	79,776
Dilutive effect of potentially dilutive securities[1]	2,656	—	—	—
Weighted-average common shares outstanding - diluted	82,898	79,879	80,277	79,776
Diluted income (loss) per share	$ 0.12	$ (0.24)	$ (0.30)	$ (2.50)

(1) We excluded approximately 0.2 million dilutive securities from the dilutive weighted-average common shares outstanding for the three months ended 2020, because their effect was anti-dilutive. We excluded approximately 2.4 million and 0.2 million dilutive securities from the dilutive weighted-average common shares outstanding for the nine months ended September 30, 2021 and 2020, because their effect was anti-dilutive.

Note 8—Revenue Recognition

We have derived most of our revenue from sales of oil, natural gas and NGLs, with the remaining revenue generated from sales of electricity and marketing activities related to transporting and marketing third-party volumes.

The following table provides disaggregated revenue for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in thousands)			
Oil sales	$ 152,536	$ 88,453	$ 416,204	$ 274,275
Natural gas sales	6,922	3,347	24,414	9,549
Natural gas liquids sales	1,600	439	3,480	1,028
Electricity sales	12,371	8,744	29,328	19,089
Marketing revenues	732	330	3,087	1,075
Other revenues	117	—	372	53
Revenues from contracts with customers	174,278	101,313	476,885	305,069
(Losses) gains on oil and gas sales derivatives	(30,864)	(11,564)	(140,021)	157,398
Total revenues and other	$ 143,414	$ 89,749	$ 336,864	$ 462,467

Note 9—Acquisition and Divestiture

Effective October 1, 2021, we completed the C&J Well Services Acquisition, acquiring the California business lines of Basic Energy Services, Inc. (“Basic”), which includes the legacy C&J Well Services, Inc. and KVS Trucking, Inc. operations, for approximately $43 million, subject to certain closing adjustments. The acquired businesses lines are owned and operated by C&J Well Services, a wholly owned subsidiary of Berry Corp. formed for the purposes of acquiring these businesses lines and establishing an independent well services company. The C&J Well Services Acquisition creates a strategic growth opportunity and further aligns Berry with the State of California's energy transition goals, including to help reduce fugitive emissions, especially methane and CO_2, from orphan and idle wells.

During the third quarter we entered into an agreement to sell our Placerita Field property in the Ventura Basin in Los Angeles County, California. As a result, we have reclassified all related balances as assets held for sale. This divestiture closed in October 2021, with no impairment.

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 ("MD&A") 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, 2020 (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) for periods prior to October 1, 2021, Berry Corporation (bry), a Delaware corporation (formerly known as Berry Petroleum Corporation, and also referred to herein as ("Berry Corp.") together with its subsidiary Berry Petroleum, LLC, a Delaware limited liability company ("Berry LLC") and (ii) for periods on or after October 1, 2021, Berry Corp. together with its subsidiaries, Berry LLC, CJ Berry Well Services Management, LLC, a Delaware limited liability company ("C&J Management"), and C&J Well Services, LLC, a Delaware limited liability company ("C&J Well Services"). Given the October 1, 2021 effective date of the C&J Well Services Acquisition (as defined below), C&J Well Services' results are not included in this MD&A and, unless the context otherwise, the disclosures included herein are solely with respect to our production business operated through Berry LLC.

Our Company

We are a western United States independent upstream energy company focused primarily on the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, with well servicing and abandonment capabilities. As of October 1, 2021, we own one of the largest upstream well servicing and abandonment providers in California with a track record of strong earnings through recent price cycles and one of the best safety records in the service industry.

Our upstream assets, owned and operated by Berry LLC, in the aggregate are characterized by high oil content and are solely in rural areas with low population. The overwhelming majority of our productive assets are located in the oil-rich reservoirs in the San Joaquin basin of Kern County, 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, which enables 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. The California oil market has Brent-linked pricing which in recent history realizes premium pricing to WTI. We also have assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah and in the low geologic risk natural gas resource play in the Piceance basin in Colorado. We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling locations with attractive full-cycle economics will support our objectives to generate "Levered Free Cash Flow" (a non-GAAP financial measure discussed under "How We Plan and Evaluate Operations" in this report) to fund our operations, optimize capital efficiency, and return capital to stockholders, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles.

We have a progressive approach to growing and evolving our businesses 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 the utility of our assets, create value for shareholders, and support environmental goals that align with a more positive future.

Recent Developments

Effective October 1, 2021, through C&J Well Services, we completed the acquisition of the California business lines of Basic Energy Services, Inc., which includes the legacy operations of C&J Well Services, Inc. and KVS Trucking, Inc. (collectively, the "C&J Well Services Acquisition"), for approximately $43 million, subject to certain closing adjustments. The purchase price was funded with cash on hand. The C&J Well Services Acquisition, creates a strategic growth opportunity and further aligns Berry with the State of California's energy transition goals to reduce fugitive emissions, especially methane and CO_2, from orphan and idle wells. Given the October 1, 2021 effective date of the C&J Well Services Acquisition, C&J Well Services' results are not included in this MD&A and, unless the context otherwise, the disclosures included herein are solely with respect to our production business.

We have also entered into an agreement to sell our Placerita Field property in the Ventura Basin in Los Angeles County, California. This was our only remaining urban asset which furthers our focus on maintaining our current portfolio in rural areas with low populations. As a result we have reclassified all related balances as assets held for sale. This divestiture closed in October 2021, with no impairment.

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; and (d) general and administrative expenses. With respect to our production business, we also measure production levels.

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 define 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 and infrequent items.

Operating Expenses

Overall, operating expense is used by management as a measure of the efficiency with which operations are performed. With respect to our production business, we define operating expenses as lease operating expenses, electricity generation expenses, transportation expenses, and marketing expenses, offset by the third-party revenues generated by electricity, transportation and marketing activities, as well as the effect of derivative settlements (received or paid) for gas purchases. Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Marketing revenues represent sales of natural gas purchased from and sold to third parties. 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, both our production and well services operations are subject to complex and stringent federal, state and local laws and regulations relating to drilling, completion, well stimulation, well servicing, operation, maintenance or abandonment of wells or facilities, managing energy, water use, land use, managing greenhouse gases or other emissions, governing the discharge of materials into the environment or otherwise relating to environmental, health and safety protection, including air quality, and the transportation, marketing, and sale of our products.

With respect to our production operations, 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 all of our operations in an ethical, safe and responsible manner, to protect the environment and to take care of our people and the communities in which we live and operate. We also seek proactive and transparent engagement with regulatory agencies, the communities in which we operate and our other stakeholders in order to realize the full potential of our resources in a timely fashion that safeguards people and the environment and complies with existing laws and regulations. We monitor our EH&S performance through various measures, holding our employees and contractors to high standards. Meeting corporate EH&S metrics, including with respect to health and safety and spill prevention, is a part of our short-term incentive program for all employees.

General and Administrative Expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities and approximately 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.

Business Environment, Market Conditions and Outlook

Our operating and financial results, same as 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.

The extent to which our full year 2021 operating and financial results, or that of future periods, will be adversely impacted by the ongoing COVID-19 pandemic and the actions of foreign oil and gas producers will depend largely on future developments, which are highly uncertain and cannot be accurately predicted. 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 OPEC+. We have taken steps and continue to work to address the challenges and mitigate repercussions from both the COVID-19 pandemic and further industry downturns on our operations, our financial condition and our people.

The recovery in the oil and gas industry has improved with increasing oil prices as more states and countries re-open and national and global economies continue to recover from the global COVID-19 pandemic. The demand for oil, while improving, could again decline if there is a widespread resurgence of the COVID-19 outbreak, although the extent of the impact on our industry and our business cannot be reasonably predicted at this time. In October 2021, OPEC+ reconfirmed their earlier agreement to continue gradually increasing oil production well into 2022, as global demand grows.

As the visibility of the long-term supply and demand for oil has improved coupled with our improving cost structure we reinstated the quarterly dividend in the first quarter of 2021, increased the dividend for the third quarter of 2021, and repurchased treasury shares during the third quarter.

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, as noted below, were higher for the three months ended September 30, 2021 compared to the three months ended June 30, 2021 and September 30, 2020. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics.

In California, the price we pay for fuel gas purchases is generally based on the Kern, Delivered Index, which was as high as $15.31 per mmbtu and as low as $3.83 per mmbtu during the third quarter of 2021, while we paid an average of $5.79 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, 2021, June 30, 2021 and September 30, 2020 and for the nine months ended September 30, 2021 and September 30, 2020:

	Three Months Ended			Nine Months Ended	
	September 30, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
Oil (bbl) – Brent	$ 73.23	$ 69.08	$ 43.34	$ 67.97	$ 42.53
Oil (bbl) – WTI	$ 70.63	$ 66.03	$ 40.87	$ 64.87	$ 38.55
Natural gas (mmbtu) – Kern, Delivered	$ 5.75	$ 3.23	$ 2.84	$ 5.65	$ 2.15
Natural gas (mmbtu) – Henry Hub	$ 4.35	$ 2.95	$ 2.00	$ 3.61	$ 1.87

As mentioned above, California oil prices are Brent-influenced as California refiners import approximately 65% to 70% of the state’s demand from OPEC+ countries and other waterborne sources. 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.

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. However, we have high operational control of our existing acreage, which provides significant upside for additional vertical and or horizontal development and recompletions.

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 the Rockies. Additionally, in recent history, the California gas markets have generally 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. We recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that help reduce our exposure to fuel gas purchase price fluctuations. Additionally, the negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce and sell in the Rockies.

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.

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 June 2022 through November 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, most notably in June through September, due to negotiated capacity payments we receive.

EH&S and Regulatory Matters

Like other companies in the oil and gas industry, both our production and well services operations are subject to complex and stringent federal, state, and local laws and regulations relating to drilling, completion, well stimulation, well servicing, operation, maintenance or abandonment of wells or facilities, managing energy, water use, land use, managing greenhouse gases or other emissions, governing the discharge of materials into the environment or otherwise relating to the protection of health, safety and the environment, protection of air quality, and the transportation, marketing, and sale of our products. Congress and federal and state agencies frequently revise the safety and environmental laws and regulations applicable to our operations, and any changes that result in more stringent and costly requirements for the oil and natural gas industry, for example for waste handling, disposal, cleanup and abandonment, could have a significant impact on operating and financial results. In many of these areas, federal, state, and local agencies may assert overlapping authority and regulations. In addition, new laws and regulations could apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors have no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

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 help ensure that we can realize the full potential of our resources in a manner that safeguards people and the environment and complies with existing laws and regulations. We monitor our environmental, health and safety, or EH&S, performance through various measures, and we hold our employees and contractors to high standards. Meeting corporate EH&S metrics, including with respect to EH&S incidents and spill prevention, is a part of our short-term incentive program for all employees. In 2020, our production operations achieved a Total Recordable Incident Rate, or TRIR, of 0.5, which is a record company low since the current management team took over in early 2017 and is below the United States average for all industries, which is a TRIR of 3.0 based on the most recently available data.

Certain actions of the new U.S. administration could negatively impact the oil and gas industry. Such actions may include, among other things, the increased regulation of greenhouse gas emissions associated with oil and gas operations, the imposition of a new carbon tax on greenhouse gas emissions and replacing tax incentives related to fossil fuel with incentives for clean energy production. Such outcomes could materially and adversely affect our business, results of operations and financial condition. Any such policies, regardless of whether they materially or adversely affect our business, may also adversely affect our stock price or ability to obtain funds.

Additionally, 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, permitting, and data collection and reporting requirements. Certain state legislators have recently sought to introduce new legislation to restrict oil and gas activities in California, however, those efforts have not been successful to date. Additionally, California Governor Gavin Newsome has advocated for and directed actions, including through executive orders, to restrict oil and gas operations and reduce both the supply and demand for oil and gas in the state. For example, in 2021:

- On April 23, 2021, Governor Newsom directed the California Geologic Energy Management Division (“CalGEM”) of the Department of Conservation, California's primary regulator of the oil and natural gas industry on private and state lands, as well as federal lands within the state's boundaries, to initiate rulemaking to halt the issuance of new permits for well stimulation treatments by 2024. It remains unclear whether or not CalGEM has existing statutory authority to take such action or whether additional enabling legislation from the California State Legislature is required. The directive also instructed the California Air Resources Board to evaluate regulatory pathways for phasing out oil extraction by 2045 under the state's climate change scoping plan, which is the state's comprehensive, programmatic plan of potential regulatory and statutory actions needed to achieve the state's intended reductions in GHG emissions. We cannot predict the ultimate outcome of this evaluation, but authority for any rulemaking to broadly prohibit the extraction of oil would likely require the introduction of new legislation and be subject to significant opposition. Other proposals to prohibit or restrict certain oil extraction methods have previously been unsuccessful in the California State Legislature.

- In response to Governor Newsom's April 23, 2021, directive summarized above, in May 2021, CalGEM published pre-rulemaking draft regulations prohibiting authorizations for well stimulation treatments after January 1, 2024. Well stimulation treatments covered by the draft rule include hydraulic fracturing, acid fracturing, acid-matrix stimulation, and other well-stimulation treatments that enhance oil and gas production by creating channels in rock formations for hydrocarbons to flow. Separately, in July 2021, CalGEM denied a set of permits for hydraulic fracturing requested by an operator, citing broadly the protection of public health and safety and environmental quality, but without indicating how the permit applications did not meet the specific regulatory requirements for approval. In response, on September 13, 2021, Kern County filed a legal challenge against Governor Newsom, and on October 8, 2021, the Western States Petroleum Association (of which we are a member) filed a separate legal challenge, alleging that CalGEM had been conducting a de facto moratorium on hydraulic fracturing and other forms of well stimulation and that the recent well stimulation permit denials were as a result of that de facto moratorium. Given the limited use of well stimulation treatments in our operations in California currently, we do not expect to be materially impacted by a potential final rule from CalGEM or the outcome of this litigation. However, we cannot predict the ultimate outcome of the final rule or this litigation, and CalGEM could issue similar permit denials or other restrictions in the future for other types of oil and gas activities. Our current operations and future plans may be impacted by pending or threatened legislative, regulatory or other government activity impacting the timing of, and conditions imposed on, the required permits and approvals governing our production-related activities.

- Prior to issuing the permits necessary for the conduct of certain operations, CalGEM requires an operator to identify the manner in which the requirements of the California Environmental Quality Act ("CEQA") have been satisfied. In Kern County, where most of our production operations are located, we typically have satisfied CalGEM's request for proof of CEQA compliance by demonstrating compliance with the local oil and gas ordinance, as supported by the Kern County Environmental Impact Report ("EIR"), which covers oil and gas operations in Kern County. In addition to CalGEM, other state agencies have allowed operators to rely on the Kern County EIR to satisfy the applicable CEQA compliance requirements in connection with permitting and project approval decisions for oil and gas projects in unincorporated Kern County. A group of plaintiffs challenged the Kern County EIR and on February 25, 2020, the California Fifth District Court of Appeals issued a ruling that invalidated a portion of the Kern County EIR, effective 30 days after entry of the ruling, unless and until Kern County made certain revisions to the Kern County EIR and recertified it ("Kern County Ruling"). To address the Kern County Ruling, Kern County elected to prepare a supplemental EIR. On February 12, 2021, the Kern County Planning Commission voted to recommend approval of the revisions in the supplemental EIR, which subsequently became effective in April 2021 upon approval by the County Board of Supervisors ("Supplemental EIR"). The plaintiffs challenged Kern County's resumption of permitting in reliance on the Supplemental EIR, noting that the County had not first obtained judicial determination that the Supplemental EIR satisfied the Kern County Ruling. On October 6, 2021, the Superior Court ruled that Kern County must immediately cease issuing permits for oil and gas operations and suspended reliance on the Supplemental EIR to satisfy CEQA compliance for the issuance of new permits until at least the end of April 2022, when a previously scheduled hearing regarding the Supplemental EIR is to be held.

- On November 2, 2021, CalGEM released a Notice to Operators ("NTO") providing guidance about how operators can proceed with permitting applications until the Supplemental EIR litigation is resolved:

operators can (1) rely upon the Supplemental EIR for CEQA compliance, but any permits granted by CalGEM will be conditional, pending favorable conclusion of the litigation for the Kern County SEIR or (2) submit requests for permits directly to CalGEM without reliance on the Supplemental SEIR and then CalGEM will act as the CEQA lead agency, evaluating environmental impacts of the proposed wells and establishing mitigation measures under CEQA. This development should not impact our 2021 results because we already have the permits in hand to support our remaining planned 2021 operations. We have already obtained some permits and submitted applications for additional permits to support our 2022 operations, and with the NTO, we are now planning accordingly to ensure we have sufficient permits to deliver our 2022 plan. Although demonstrating CEQA compliance without reliance on an EIR may be a more time and cost intensive process, we are knowledgeable of the process outlined in the NTO and have in the past successfully navigated it to timely obtain permits.

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.

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 and completion objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, our operations may have been and in the future may be impacted by ice and snow in the winter, especially in Utah, and by electrical storms and high temperatures in the spring and summer, as well as by wild fires and rain.

Natural gas prices fluctuate based on seasonal and other market-related impacts. We purchase significantly more gas than we sell to generate steam and electricity in our cogeneration facilities for our producing activities. As a result, our key exposure to gas prices is in our costs. We mitigate a substantial portion of this exposure by selling excess electricity from our cogeneration operations to third parties. The pricing of these electricity sales is closely tied to the purchase price of natural gas. These sales are generally higher in the summer months as they include seasonal capacity amounts. We also hedge a significant portion of the gas we expect to consume and we recently entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our operations in California.

Capital Expenditures

For the three and nine months ended September 30, 2021, our capital expenditures were approximately $38 million and $105 million, respectively, on an accrual basis including capitalized overhead and interest and excluding acquisitions and asset retirement spending. Approximately 78% and 15% of capital expenditures for the nine months ended September 30, 2021 was directed to California oil and Utah operations, respectively.

Our planned 2021 capital expenditure budget is approximately $120 to $130 million. As planned, we spent the majority of this amount during the second and third quarters of 2021. We are currently on track to spend within our 2021 capital budget. We expect our capital expenditures will result in essentially flat year-over year production and a higher exit rate for 2021 than 2020. We currently anticipate oil production will be approximately 89% of total production in 2021, compared to 88% in 2020. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2021 capital development programs with Levered Free Cash Flow.

The amount and timing of capital expenditures are within our control and subject to our discretion, and due to the speed with which we are able to drill and complete our wells in California, capital may be adjusted quickly during the year depending on numerous factors, including commodity prices, storage constraints, supply/demand considerations and attractive rates of return. We believe it is important to retain the flexibility to defer planned capital expenditures and may do so based 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. Any postponement or elimination of our development drilling program could result in a reduction of proved reserves volumes and materially affect our business, financial condition and results of operations. Additionally and not included in the capital expenditures noted above, for the full year 2021, we plan to spend approximately $16 million to $20 million on plugging and abandonment activities, including satisfying our annual obligations under the California Idle Well Management Program. We spent approximately $5 million and $12 million for plugging and abandonment activities in the third quarter and the first three quarters of 2021, respectively.

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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, 2021	June 30, 2021	September 30, 2020
Oil, natural gas and natural gas liquids sales	$ 140,160	$ 129,128	$ 81,592
Operating income[(1)]	$ 26,652	$ 11,413	$ 36,296
Depreciation, depletion, and amortization (DD&A)	$ 35,252	$ 35,174	$ 34,779
Average daily production (mboe/d)	21.8	21.7	22.2
Production (oil % of total)	100 %	100 %	100 %
Realized sales prices:			
Oil (per bbl)	$ 69.92	$ 65.37	$ 40.02
NGLs (per bbl)	$ —	$ —	$ —
Gas (per mcf)	$ —	$ —	$ —
Capital expenditures[(2)]	$ 29,806	$ 31,303	$ 4,467

($ in thousands, except prices)	Utah (Uinta basin) Three Months Ended September 30, 2021	June 30, 2021	September 30, 2020	Colorado (Piceance basin) Three Months Ended September 30, 2021	June 30, 2021	September 30, 2020
Oil, natural gas and natural gas liquids sales	$ 18,118	$ 16,199	$ 9,311	$ 2,779	$ 2,438	$ 1,336
Operating income (loss)[(1)]	$ 7,246	$ 6,736	$ 1,093	$ 2,360	$ 1,121	$ (235)
Depreciation, depletion, and amortization (DD&A)	$ 611	$ 630	$ 915	$ 38	$ 38	$ 165
Average daily production (mboe/d)	4.4	4.4	4.1	1.2	1.2	1.3
Production (oil % of total)	50 %	52 %	47 %	1 %	2 %	2 %
Realized sales prices:						
Oil (per bbl)	$ 60.09	$ 58.55	$ 38.40	$ 66.97	$ 56.05	$ 33.60
NGLs (per bbl)	$ 40.88	$ 29.61	$ 13.25	$ —	$ —	$ —
Gas (per mcf)	$ 4.31	$ 3.30	$ 2.05	$ 4.24	$ 3.53	$ 1.80
Capital expenditures[(2)]	$ 5,728	$ 9,162	$ 103	$ —	$ —	$ 46

(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, 2021	June 30, 2021	September 30, 2020
Average daily production:[(1)]			
Oil (mbbl/d)	24.1	24.0	24.1
Natural Gas (mmcf/d)	17.6	17.5	18.7
NGL (mbbl/d)	0.4	0.4	0.4
Total (mboe/d)[(2)]	27.4	27.3	27.6
Total Production:			
Oil (mbbl)	2,211	2,183	2,218
Natural gas (mmcf)	1,615	1,595	1,719
NGLs (mbbl)	39	36	33
Total (mboe)[(2)]	2,519	2,485	2,537
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 69.01	$ 64.72	$ 39.88
Effects of scheduled derivative settlements ($/bbl)	$ (14.66)	$ (18.33)	$ 16.28
Oil with hedges ($/bbl)	$ 54.35	$ 46.39	$ 56.16
Natural gas ($/mcf)	$ 4.29	$ 3.39	$ 1.95
NGL ($/bbl)	$ 40.88	$ 29.61	$ 13.25
Average Benchmark prices:			
Oil (bbl) – Brent	$ 73.23	$ 69.08	$ 43.34
Oil (bbl) – WTI	$ 70.63	$ 66.03	$ 40.87
Natural gas (mmbtu) – Kern, Delivered[(3)]	$ 5.75	$ 3.23	$ 2.84
Natural gas (mmbtu) – Henry Hub[(4)]	$ 4.35	$ 2.95	$ 2.00

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $73.23 per bbl and $4.35 per mmbtu.

(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, 2021	June 30, 2021	September 30, 2020
Average daily production (mboe/d):[(1)]			
California	21.8	21.7	22.2
Utah	4.4	4.4	4.1
Colorado	1.2	1.2	1.3
Total average daily production	27.4	27.3	27.6

(1) Production represents volumes sold during the period.

Average daily production and company-wide oil production each increased slightly by 0.1 mboe/d for the three months ended September 30, 2021, compared to the three months ended June 30, 2021. Our California production of 21.8 mboe/d for the third quarter 2021 increased 0.1 mboe/d from the second quarter 2021. We drilled 56 wells in the third quarter. Capital for the third quarter was $5 million lower than the second quarter, as fewer wells were drilled, including just two wells drilled in Utah, six fewer than the second quarter, which require more capital than typical California wells. Additionally, in California, the Company had slightly lower California workover, equipping and facilities activity in the third quarter of 2021. California development in the third quarter was focused on steam flood expansion projects which ramp up to full production in a few months. Production for the third quarter was impacted by the onboarding of a new drilling operator and an industry-wide shortage of truck drivers. The overwhelming majority of these issues were mitigated by the end of the third quarter.

Average daily production for the three months ended September 30, 2021 was 1% or 0.2 mboe/d lower than the three months ended September 30, 2020. In 2021, we have deployed more capital than 2020 following the significant price deterioration in 2020, and we are beginning to stabilize the decline caused by the lack of development in 2020.

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, 2021	September 30, 2020
Average daily production:[1]		
Oil (mbbl/d)	24.0	25.7
Natural Gas (mmcf/d)	17.3	18.8
NGL (mbbl/d)	0.4	0.3
Total (mboe/d)[2]	27.3	29.1
Total Production:		
Oil (mbbl)	6,545	7,033
Natural gas (mmcf)	4,728	5,148
NGLs (mbbl)	105	94
Total (mboe)[2]	7,438	7,985
Weighted-average realized sales prices:		
Oil without hedges ($/bbl)	$ 63.59	$ 39.00
Effects of scheduled derivative settlements ($/bbl)	$ (15.03)	$ 16.97
Oil with hedges ($/bbl)	$ 48.56	$ 55.97
Natural gas ($/mcf)	$ 5.16	$ 1.85
NGL ($/bbl)	$ 32.97	$ 10.92
Average Benchmark prices:		
Oil (bbl) – Brent	$ 67.97	$ 42.53
Oil (bbl) – WTI	$ 64.87	$ 38.55
Gas (mmbtu) – Kern, Delivered[3]	$ 5.65	$ 2.15
Natural gas (mmbtu) – Henry Hub[4]	$ 3.61	$ 1.87

(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, 2021, the average prices of Brent oil and Henry Hub natural gas were $67.97 per bbl and $3.61 per mmbtu respectively.

(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, 2021	September 30, 2020
Average daily production (mboe/d):[(1)]		
California	21.8	23.5
Utah	4.3	4.3
Colorado	1.2	1.3
Total average daily production	27.3	29.1

(1) Production represents volumes sold during the period.

Average daily production decreased 6% for the nine months ended September 30, 2021, compared to the nine months ended September 30, 2020, due to reduced development in 2020 as a result of significant price deterioration.

Results of Operations

Three Months Ended September 30, 2021 compared to Three Months Ended June 30, 2021.

	Three Months Ended			
	September 30, 2021	June 30, 2021	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 161,058	$ 147,775	$ 13,283	9 %
Electricity sales	12,371	6,888	5,483	80 %
Losses on oil and gas sales derivatives	(30,864)	(55,653)	24,789	(45)%
Marketing and other revenues	849	239	610	255 %
Total revenues and other	$ 143,414	$ 99,249	$ 44,165	44 %

Revenues and Other

Oil, natural gas and NGL sales increased by $13 million, or 9%, to approximately $161 million for the three months ended September 30, 2021, compared to the three months ended June 30, 2021. The increase was driven by $11 million and $2 million higher unhedged oil prices and oil sales volumes, respectively.

Electricity sales represent sales to utilities, and increased $5 million, or 80%, to approximately $12 million for the three months ended September 30, 2021 compared to the three months ended June 30, 2021. The increase was primarily attributed to higher unit sales prices driven by higher natural gas prices and to a lesser degree higher summer electricity rates.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement loss for the three months ended September 30, 2021 was $32 million and the loss for the three months ended June 30, 2021 was $40 million. The quarter-over-quarter decrease in settlement losses was driven by a decrease in notional volumes and an increase in average swap strike prices in the third quarter compared to those of the second quarter of 2021. The average derivative fixed price increased to $49.82 in the third quarter when compared to $45.82 in the second quarter and notional volumes decreased to 14 mbbl/d in the third quarter from 19 mbbl/d in the second quarter 2021. The mark-to-market non-cash gain of $1 million for the three months ended September 30, 2021 was due to additional hedges added in the quarter, compared to the non-cash loss of $16 million for the three months end June 30, 2021 when average fixed prices were less than market.

Marketing and other revenues increased by approximately $1 million for the three months ended September 30, 2021 when compared to the three months ended June 30, 2021 due to higher natural gas prices.

	Three Months Ended			
	September 30, 2021	June 30, 2021	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 60,930	$ 45,543	$ 15,387	34 %
Electricity generation expenses	7,128	4,712	2,416	51 %
Transportation expenses	1,806	1,757	49	3 %
Marketing expenses	715	44	671	1,525 %
General and administrative expenses	17,614	16,065	1,549	10 %
Depreciation, depletion and amortization	35,902	35,850	52	— %
Taxes, other than income taxes	13,420	11,603	1,817	16 %
Gains on natural gas purchase derivatives	(14,980)	(11,639)	(3,341)	29 %
Other operating expenses	3,986	42	3,944	9,390 %
Total expenses and other	126,521	103,977	22,544	22 %
Other (expenses) income:				
Interest expense	(7,810)	(8,217)	407	(5)%
Other, net	(5)	(8)	3	(38)%
Income (loss) before income taxes	9,078	(12,953)	22,031	170 %
Income tax benefit	(758)	(72)	(686)	953 %
Net income (loss)	$ 9,836	$ (12,881)	$ 22,717	176 %
Expenses per boe:[(1)]				
Lease operating expenses	$ 24.20	$ 18.33	$ 5.87	32 %
Electricity generation expenses	2.83	1.90	0.93	49 %
Electricity sales[(1)]	(4.91)	(2.77)	(2.14)	77 %
Transportation expenses	0.72	0.70	0.02	3 %
Transportation sales[(1)]	(0.05)	(0.05)	—	— %
Marketing expenses	0.28	0.02	0.26	1,300 %
Marketing revenues[(1)]	(0.29)	(0.05)	(0.24)	480 %
Derivatives settlements received for gas purchases[(1)]	(5.60)	(0.77)	(4.83)	627 %
Total operating expenses	$ 17.18	$ 17.31	$ (0.13)	(1)%
Total unhedged operating expenses[(2)]	$ 22.78	$ 18.08	$ 4.70	26 %
Total non-energy operating expenses[(3)]	$ 13.59	$ 12.71	$ 0.88	7 %
Total energy operating expenses[(4)]	$ 3.59	$ 4.60	$ (1.01)	(22)%
General and administrative expenses[(5)]	$ 6.99	$ 6.46	$ 0.53	8 %
Depreciation, depletion and amortization	$ 14.25	$ 14.43	$ (0.18)	(1)%
Taxes, other than income taxes	$ 5.33	$ 4.67	$ 0.66	14 %

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.66 per boe and $1.11 per boe for the three months ended September 30, 2021 and June 30, 2021, respectively.

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”, which include electricity, marketing and transportation revenues. On a hedged basis, operating expenses decreased by 1%, or $0.13 per boe to $17.18 for the third quarter 2021 compared to the second quarter 2021. During the third quarter, energy operating expenses improved as increased electricity revenue and gas purchase hedging more than offset higher natural gas prices. Non-energy operating expenses increased slightly on a per boe basis, compared to the second quarter of 2021.

Unhedged lease operating expenses per boe increased to $24.20, for the three months ended September 30, 2021, a 32% or $5.87 per boe increase compared to $18.33 per boe for the three months ended June 30, 2021 driven by $5.95 per boe of higher unhedged fuel costs for our California steam operations. Unhedged average fuel purchase price per mmbtu increased 75% in the third quarter 2021 compared to the three months ended June 30, 2021. Key non-fuel lease operating expense increases included higher well maintenance activity, power prices, outside services and facility costs, partially offset by lower steam facility costs.

Electricity generation expenses increased approximately 49% to $2.83 per boe for the three months ended September 30, 2021, compared to $1.90 per boe for the three months ended June 30, 2021 due to higher natural gas costs. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Gains and losses on natural gas purchase derivatives resulted in a $15 million gain for the three months ended September 30, 2021 and a gain of $12 million in the three months ended June 30, 2021. Settlement gains for the three months ended September 30, 2021 and June 30, 2021 were $14 million or $5.60 per boe and $2 million or $0.77 per boe, respectively, and increased due to higher gas prices. The mark-to-market valuation gain was $1 million for the three months ended September 30, 2021 and $10 million for the three months ended June 30, 2021 due to higher futures prices relative to the derivative fixed prices at the end of each period.

Transportation expense increased slightly to $0.72 per boe for the three months ended September 30, 2021 compared to $0.70 per boe for the three months ended June 30, 2021.

Marketing expenses increased by $0.26 per boe for the three months ended September 30, 2021 when compared to the three months ended June 30, 2021, due to higher natural gas prices.

General and administrative expenses increased by $1.5 million, or 10%, to $17.6 million for the three months ended September 30, 2021, compared to the three months ended June 30, 2021, due to the following matters and those noted in adjusted general and administrative expenses below. For the three months ended September 30, 2021 and June 30, 2021, general and administrative expenses included non-cash stock compensation costs of approximately $3.5 million and $2.8 million, respectively. We incurred approximately $0.7 million of legal and professional service expenses related to acquisition and divestiture activity which have been categorized as non-recurring for the three months ended September 30, 2021. 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 essentially flat at $13.4 million for the three months ended September 30, 2021 compared to $13.3 million for the three months ended June 30, 2021. On a per boe basis, adjusted general and administrative expenses decreased to $5.34 per boe from $5.35 per boe in the second quarter 2021 due to the impact of higher production. 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 was flat for the three months ended September 30, 2021 compared to the three months ended June 30, 2021.

Taxes, Other Than Income Taxes

	Three Months Ended			
	September 30, 2021	**June 30, 2021**	**$ Change**	**% Change**
	(per boe)			
Severance taxes	$ 0.80	$ 0.97	$ (0.17)	(18)%
Ad valorem and property taxes	1.73	1.99	(0.26)	(13)%
Greenhouse gas allowances	2.80	1.71	1.09	64 %
Total taxes other than income taxes	$ 5.33	$ 4.67	$ 0.66	14 %

Taxes, other than income taxes, increased in the three months ended September 30, 2021 by $0.66 per boe, or 14%, to $5.33. Severance taxes were lower in the third quarter of 2021 due to lower assessment rates. Ad valorem and property taxes were lower in the third quarter of 2021 due to supplemental assessments received in the second quarter of 2021 and none received in the third quarter. Greenhouse gas ("GHG") costs were higher in the third quarter of 2021 due to higher mark-to-market valuations.

Other Operating Expenses

For the three months ended September 30, 2021, other operating expenses was $4 million and mainly consisted of expensing $3 million of unamortized debt issuance costs related to the termination of the 2017 RBL Facility. Other operating expenses for the three months ended June 30, 2021 was less than $0.1 million and mainly consisted of $2 million of supplemental property tax assessments and royalty audit charges offset by $2 million of income from employee retention credits.

Interest Expense

Interest expense was relatively flat at $8 million for each of the three months ended September 30, 2021 and June 30, 2021.

Income Tax Benefit

Our effective tax rate was approximately (8)% and 1% for the three months ended September 30, 2021 and June 30, 2021, respectively. The rates were negatively impacted as we recorded valuation allowances on a large portion of our tax credits, net operating loss carryforwards and on other deferred tax assets as a result of estimated future realizability.

Three Months Ended September 30, 2021 compared to Three Months Ended September 30, 2020.

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 161,058	$ 92,239	$ 68,819	75 %
Electricity sales	12,371	8,744	3,627	41 %
Losses on oil and gas sales derivatives	(30,864)	(11,564)	(19,300)	167 %
Marketing and other revenues	849	330	519	157 %
Total revenues and other	$ 143,414	$ 89,749	$ 53,665	60 %

Revenues and Other

Oil, natural gas and NGL sales increased by $69 million, or 75% to approximately $161 million for the three months ended September 30, 2021 when compared to the three months ended September 30, 2020. This variance was almost entirely the result of higher unhedged commodity prices.

Electricity sales represent sales to utilities, and increased by $3.6 million, or 41%, to approximately $12 million for the three months ended September 30, 2021 when compared to the three months ended September 30, 2020. The increase was largely due to higher unit sales prices driven by higher natural gas prices.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement loss for the three months ended September 30, 2021 was $32 million compared to the gain for the three months ended September 30, 2020 of $36 million. The quarter-over-quarter change from settlement gains to losses was driven by higher oil prices in the third quarter 2021 relative to our derivative fixed prices. Additionally, notional volumes decreased to 14 mbbl/d in the third quarter 2021 from 24 mbbl/d in the third quarter 2020. The mark-to-market non-cash gain of $1 million for the three months ended September 30, 2021 was due to additional hedges added during the quarter. 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.

Marketing and other revenues increased due to higher natural gas prices.

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 60,930	$ 45,243	$ 15,687	35 %
Electricity generation expenses	7,128	4,217	2,911	69 %
Transportation expenses	1,806	1,768	38	2 %
Marketing expenses	715	326	389	119 %
General and administrative expenses	17,614	19,173	(1,559)	(8)%
Depreciation, depletion and amortization	35,902	35,905	(3)	— %
Taxes, other than income taxes	13,420	9,913	3,507	35 %
Gains on natural gas purchase derivatives	(14,980)	(15,784)	804	(5)%
Other operating expenses	3,986	1,648	2,338	142 %
Total expenses and other	126,521	102,409	24,112	24 %
Other (expenses) income:				
Interest expense	(7,810)	(8,391)	581	(7)%
Other, net	(5)	(3)	(2)	67 %
Income (loss) before income taxes	9,078	(21,054)	30,132	143 %
Income tax benefit	(758)	(2,190)	1,432	(65)%
Net income (loss)	$ 9,836	$ (18,864)	$ 28,700	152 %
Expenses per boe:[(1)]				
Lease operating expenses	$ 24.20	$ 17.83	$ 6.37	36 %
Electricity generation expenses	2.83	1.66	1.17	70 %
Electricity sales[(1)]	(4.91)	(3.45)	(1.46)	42 %
Transportation expenses	0.72	0.69	0.03	4 %
Transportation sales[(1)]	(0.05)	—	(0.05)	100 %
Marketing expenses	0.28	0.13	0.15	115 %
Marketing revenues[(1)]	(0.29)	(0.13)	(0.16)	123 %
Derivatives settlements (received) paid for gas purchases[(1)]	(5.60)	0.24	(5.84)	n/a
Total operating expenses	$ 17.18	$ 16.97	$ 0.21	1 %
Total unhedged operating expenses[(2)]	$ 22.78	$ 16.73	$ 6.05	36 %
Total non-energy operating expenses[(3)]	$ 13.59	$ 13.34	$ 0.25	2 %
Total energy operating expenses[(4)]	$ 3.59	$ 3.65	$ (0.06)	(2)%
General and administrative expenses[(5)]	$ 6.99	$ 7.56	$ (0.57)	(8)%
Depreciation, depletion and amortization	$ 14.25	$ 14.15	$ 0.10	1 %
Taxes, other than income taxes	$ 5.33	$ 3.91	$ 1.42	36 %

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.66 per boe and $2.08 per boe for the three months ended September 30, 2021 and September 30, 2020, respectively.

Expenses and Other

On a hedged basis, operating expenses, increased by 1% or $0.21 per boe to $17.18 per boe for the third quarter 2021 compared to $16.97 per boe for the third quarter 2020. The increase was due to higher non-energy operating expense partially offset by lower energy operating expense.

Unhedged lease operating expenses were $24.20 per boe for the three months ended September 30, 2021, a 36% or $6.37 boe increase compared to $17.83 for the three months ended September 30, 2020 driven by 106% or $7.24 per boe higher unhedged fuel costs for our California steam operations. Unhedged average fuel purchase price per mmbtu increased 109% in the third quarter 2021 compared to the third quarter 2020. Key non-fuel lease operating expense increases included higher well maintenance and recompletion activities, partially offset by lower facility costs.

Electricity generation expenses increased approximately 70% to $2.83 per boe for the three months ended September 30, 2021 from $1.66 per boe for the same period in 2020 due to higher natural gas costs. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements.

Gains on natural gas purchase derivatives for the three months ended September 30, 2021 and September 30, 2020 resulted in a gain of $15 million and $16 million, respectively. Settlements gains for the three months ended September 30, 2021 were $14 million or $5.60 per boe compared to the settlement loss of $1 million or $0.24 per boe for the three months ended September 30, 2020, driven by higher gas prices in 2021 compared to 2020. The mark-to-market valuation gain for the three months ended September 30, 2021 was $1 million compared to $16 million gain for the same period in 2020, 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 remained essentially flat for the three months ended September 30, 2021 and September 30, 2020.

Marketing expenses increased to $0.28 per boe for the three months ended September 30, 2021, compared to $0.13 per boe for the three months ended September 30, 2020, mostly due to higher gas prices.

General and administrative expenses decreased $2 million, or 8%, to approximately $18 million for the three months ended September 30, 2021 compared to the three months ended September 30, 2020. For the three months ended September 30, 2021 and September 30, 2020, general and administrative expenses included non-cash stock compensation costs of approximately $3.5 million and $3.8 million, respectively, with $0.7 million non-recurring costs in 2021 and $1.5 million in 2020. We incurred approximately $0.7 million of legal and other professional services costs related to acquisition and divestiture activity which have been categorized as non-recurring for the three months ended September 30, 2021.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased 4% to $13.4 million for the three months ended September 30, 2021 compared to $13.9

million for the three month periods ended September 30, 2020. The decrease was primarily due to lower professional service expenses and employee costs.

DD&A for the third quarter 2021 was flat at $36 million when compared to the third quarter 2020.

Taxes, Other Than Income Taxes

	Three Months Ended September 30,			
	2021	2020	$ Change	% Change
	(per boe)			
Severance taxes	$ 0.80	$ 0.82	$ (0.02)	(2)%
Ad valorem and property taxes	1.73	1.60	0.13	8 %
Greenhouse gas allowances	2.80	1.49	1.31	88 %
Total taxes other than income taxes	$ 5.33	$ 3.91	$ 1.42	36 %

Taxes, other than income taxes increased 36% to $5.33 per boe for the three months ended September 30, 2021 compared to $3.91 per boe for the three months ended September 30, 2020. Severance taxes are flat from the prior year. Ad valorem and property taxes increased due to higher California tax assessments. Greenhouse gas ("GHG") costs were higher in the third quarter of 2021 due to higher mark-to-market valuations.

Other Operating Expenses (Income)

For the three months ended September 30, 2021, other operating expenses was $4 million and mainly consisted of expensing $3 million of unamortized debt issuance costs related to the termination of the 2017 RBL Facility. Other operating income for the three months ended September 30, 2020 was $2 million and comprised mainly of sales tax and bankruptcy-related refunds, partially offset by excess abandonment costs.

Interest Expense

Interest expense was comparable in the three months ended September 30, 2021 and September 30, 2020.

Income Tax Benefit

Our effective tax rate was approximately (8)% for the three months ended September 30, 2021 compared to 10% for the three months ended September 30, 2020. The rates were negatively impacted as we recorded valuation allowances on a large portion of our tax credits, net operating loss carryforwards and on other deferred tax assets as a result of estimated future realizability.

Nine Months Ended September 30, 2021 compared to Nine Months Ended September 30, 2020.

	Nine Months Ended September 30,			
	2021	2020	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 444,098	$ 284,852	$ 159,246	56 %
Electricity sales	29,328	19,089	10,239	54 %
(Losses) gains on oil and gas sales derivatives	(140,021)	157,398	(297,419)	n/a
Marketing and other revenues	3,459	1,128	2,331	207 %
Total revenues and other	$ 336,864	$ 462,467	$ (125,603)	(27)%

Revenues and Other

Oil, natural gas and NGL sales increased by $159 million, or 56% to approximately $444 million for the nine months ended September 30, 2021 when compared to the nine months ended September 30, 2020. The increase was driven by higher realized prices.

Electricity sales which represent sales to utilities increased $10 million or 54% to $29 million for the nine months ended September 30, 2021 when compared to the nine months ended September 30, 2020. The increase was due to higher unit sales prices which were the result of higher natural gas prices.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. For the nine months ended September 30, 2021 we had settlement losses of $96 million and gains of $119 million for the nine months ended September 30, 2020. The period over period shift from settlement gains to settlement losses was driven by higher oil prices relative to the derivative fixed prices in the nine months ended September 30, 2021, compared to lower oil prices relative to the derivatives fixed prices in the nine months ended September 30, 2020. Additionally, notional volumes decreased to 17 mbbl/d in the nine months ended 2021 from 22 mbbl/d in the nine months ended 2020. The mark-to-market non-cash loss of $44 million for the nine months ended September 30, 2021 was due to higher futures prices relative to the derivative fixed prices at September 30, 2021 and conversely the gain of $38 million for the nine months ended September 30, 2020, was primarily due to lower futures prices relative to the derivative fixed prices at September 30, 2020.

Marketing and other revenues were higher for the nine months ended September 30, 2021, compared to the nine months ended September 30, 2020 due to higher average gas prices.

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 168,756	$ 136,727	$ 32,029	23 %
Electricity generation expenses	19,488	11,186	8,302	74 %
Transportation expenses	5,139	5,379	(240)	(4)%
Marketing expenses	2,986	1,036	1,950	188 %
General and administrative expenses	50,749	57,287	(6,538)	(11)%
Depreciation, depletion and amortization	105,592	108,746	(3,154)	(3)%
Impairment of oil and gas properties	—	289,085	(289,085)	(100)%
Taxes, other than income taxes	34,580	24,714	9,866	40 %
Gains on natural gas purchase derivatives	(54,349)	(2,824)	(51,525)	1,825 %
Other operating expenses	4,827	2,658	2,169	82 %
Total expenses and other	337,768	633,994	(296,226)	(47)%
Other (expenses) income:				
Interest expense	(24,513)	(25,987)	1,474	(6)%
Other, net	(156)	(15)	(141)	940 %
Loss before income taxes	(25,573)	(197,529)	171,956	(87)%
Income tax (benefit) expense	(1,206)	1,536	(2,742)	(179)%
Net loss	$ (24,367)	$ (199,065)	$ 174,698	(88)%
Expenses per boe:[1]				
Lease operating expenses	$ 22.69	$ 17.12	$ 5.57	33 %
Electricity generation expenses	2.62	1.40	1.22	87 %
Electricity sales[1]	(3.94)	(2.39)	(1.55)	65 %
Transportation expenses	0.69	0.67	0.02	3 %
Transportation sales[1]	(0.05)	(0.01)	(0.04)	400 %
Marketing expenses	0.40	0.13	0.27	208 %
Marketing revenues[1]	(0.42)	(0.12)	(0.30)	250 %
Derivatives settlements (received) paid for gas purchases[1]	(5.68)	1.55	(7.23)	n/a
Total operating expenses	$ 16.31	$ 18.35	$ (2.04)	(11)%
Total unhedged operating expenses[2]	$ 21.99	$ 16.80	$ 5.19	31 %
Total non-energy operating expenses[3]	$ 13.02	$ 13.41	$ (0.39)	(3)%
Total energy operating expenses[4]	$ 3.29	$ 4.94	$ (1.65)	(33)%
General and administrative expenses[5]	$ 6.82	$ 7.17	$ (0.35)	(5)%
Depreciation, depletion and amortization	$ 14.20	$ 13.62	$ 0.58	4 %
Taxes, other than income taxes	$ 4.65	$ 3.10	$ 1.55	50 %

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.43 per boe and $1.85 per boe for the nine months ended September 30, 2021 and September 30, 2020, respectively.

Expenses and Other

On a hedged basis, operating expenses, decreased 11% or $2.04 per boe to $16.31 for the nine months ended September 30, 2021 from $18.35 per boe for the nine months ended September 30, 2020. Our continuing emphasis on cost savings and efficiency initiatives, which began in the second quarter of 2020, demonstrated meaningful results for the nine months ended September 30, 2021 compared to same period of 2020 as non-energy costs declined $10 million on an absolute dollar basis and 3% or $0.39 per boe to $13.02 per boe.

Unhedged lease operating expenses were $22.69 per boe for the nine months ended September 30, 2021, a 33% or $5.57 per boe increase compared to $17.12 for the nine months ended September 30, 2020 driven by $7.14 per boe higher unhedged fuel costs, for our California steam operations. Unhedged average fuel purchase price per mmbtu increased 135% in the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020. Key non-fuel lease operating expense decreases included lower facilities costs and outside services, partially offset by higher well maintenance and recompletion activities.

Electricity generation expenses increased approximately 87% to $2.62 per boe for the nine months ended September 30, 2021 from $1.40 per boe for the same period in 2020 due to the previously discussed higher natural gas costs. 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 nine months ended September 30, 2021 and September 30, 2020 consisted of gains of $54 million and $3 million, respectively. The settlement gain for the nine months ended September 30, 2021 was $42 million, or $5.68 per boe, compared to a loss of $12 million, or $1.55 per boe for same period in 2020, driven by higher gas prices in 2021 compared to 2020. The mark-to-market valuation gain for the nine months ended September 30, 2021 was $12 million compared to $15 million for the same period in 2020, consistent with the changes in future 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 comparable for the periods presented.

Marketing expenses increased to $0.40 per boe for the nine months ended September 30, 2021, compared to $0.13 per boe for the nine months ended September 30, 2020 largely due to higher natural gas prices.

General and administrative expenses decreased $7 million, or 11%, to approximately $51 million for the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020. For the nine months ended September 30, 2021 and September 30, 2020, general and administrative expenses included non-cash stock compensation costs of approximately $10 million and $11 million, respectively. We incurred approximately $0.7 million of legal and other professional services costs related to acquisition and divestiture activity which have been categorized as non-recurring for the nine months ended September 30, 2021. Non-recurring expenses in the same period of 2020 were $4 million.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased $3 million, or 6% to $40 million for the nine months ended September 30, 2021 compared to $43 million for the nine months ended September 30, 2020. The year-over-year decrease was primarily due to lower employee costs.

DD&A decreased $3 million, or 3%, to approximately $106 million for the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020, primarily due to lower sales volumes compared to the same period in 2020. On a per boe basis, period-over-period DD&A increased $0.58 per boe to $14.20 from $13.62 due to higher depletion rates in 2021, compared to 2020.

Impairment of oil and gas properties

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,			
	2021	2020	$ Change	% Change
	(per boe)			
Severance taxes	$ 0.92	$ 0.74	$ 0.18	24 %
Ad valorem and property taxes	1.91	1.46	0.45	31 %
Greenhouse gas allowances	1.82	0.90	0.92	102 %
Total taxes other than income taxes	$ 4.65	$ 3.10	$ 1.55	50 %

Taxes, other than income taxes increased $1.55 to $4.65 per boe for the nine months ended September 30, 2021 compared to $3.10 per boe for the nine months ended September 30, 2020. The increase was largely due to higher greenhouse gas mark-to-market valuations at September 30, 2021 partially offset by allowance purchases we made at low prices and lower emissions. During 2021, we experienced higher California property tax rates, as well as higher severance taxes due to increased revenues in Utah.

Other Operating Expenses (Income)

For the nine months ended September 30, 2021 and 2020 other operating expenses were $5 million and $3 million, respectively. For the nine months ended September 30, 2021, other operating expenses mainly consisted of expensing $3 million of unamortized debt issuance costs related to the 2017 RBL Facility, approximately $3 million of supplemental property tax assessments, royalty audit charges and tank rental costs and $1 million of various other costs such as abandonment costs and legal fees, partially offset by $2 million of income from employee retention credits. For the nine months ended September 30, 2020, other operating expenses included $2 million of excess abandonment costs, $1 million of oil tank storage fees, and $1 million of drilling rig standby charges, partially offset by $1 million of tax and other refunds.

Interest Expense

Interest expense was comparable in the nine months ended September 30, 2021 and September 30, 2020.

Income Tax (Benefit) Expense

Our effective tax rate was 5% and (1)% for the nine months ended September 30, 2021 and September 30, 2020, respectively. The rates in 2021 and 2020 were negatively impacted as we recorded valuation allowances on a large portion of our tax credits, net operating loss carryforwards and on other deferred tax assets as a result of estimated 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, Levered Free Cash Flow and Adjusted Net Income (Loss) 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 and infrequent 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 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 and infrequent 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 unusual and infrequent 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, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
			(in thousands)		
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$ 9,836	$ (12,881)	$ (18,864)	$ (24,367)	$ (199,065)
Add (Subtract):					
Interest expense	7,810	8,217	8,391	24,513	25,987
Income tax (benefit) expense	(758)	(72)	(2,190)	(1,206)	1,536
Depreciation, depletion and amortization	35,902	35,850	35,905	105,592	108,746
Impairment of oil and gas properties	—	—	—	—	289,085
Losses (gains) on derivatives	15,885	44,014	(4,220)	85,672	(160,222)
Net cash (paid) received for scheduled derivative settlements	(17,622)	(37,431)	35,476	(54,204)	106,975
Other operating expenses	3,986	42	1,648	4,827	2,658
Stock compensation expense	3,580	2,860	3,896	10,219	11,397
Non-recurring costs	705	—	1,473	705	3,651
Adjusted EBITDA	$ 59,324	$ 40,599	$ 61,515	$ 151,751	$ 190,748

	Three Months Ended			Nine Months Ended	
	September 30, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
			(in thousands)		
Adjusted EBITDA reconciliation to net cash provided by operating activities and Levered Free Cash Flow calculation:					
Net cash provided by operating activities	$ 22,399	$ 21,429	$ 57,997	$ 82,258	$ 144,419
Add (Subtract):					
Cash interest payments	14,189	288	14,435	29,114	29,962
Cash income tax payments	294	—	221	294	222
Non-recurring costs	705	—	1,473	705	3,651
Other changes in operating assets and liabilities	21,737	18,882	(12,611)	39,380	12,494
Adjusted EBITDA	$ 59,324	$ 40,599	$ 61,515	$ 151,751	$ 190,748
Subtract:					
Capital expenditures - accrual basis	(38,016)	(43,461)	(5,918)	(105,046)	(62,321)
Interest expense	(7,810)	(8,217)	(8,391)	(24,513)	(25,987)
Cash dividends declared	(4,806)	(3,219)	—	(11,499)	(9,564)
Levered Free Cash Flow[(1)]	$ 8,692	$ (14,298)	$ 47,206	$ 10,693	$ 92,876

(1) Levered Free Cash Flow, as defined by the Company, includes cash paid for scheduled derivative settlements of $18 million and $37 million for the three months ended September 30, 2021 and June 30, 2021, respectively, and $54 million for the nine months ended September 30, 2021. Levered Free Cash Flow, as defined by the Company, includes cash received for scheduled derivative settlements of $35 million and $107 million for the three and nine months ended September 30, 2020, 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, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
			(in thousands)		
Adjusted Net Income (Loss) reconciliation to net income (loss):					
Net income (loss)	$ 9,836	$ (12,881)	$ (18,864)	$ (24,367)	$ (199,065)
Add: discrete income tax items	—	—	(2,394)	—	44,306
Add (Subtract):					
Losses (gains) on derivatives	15,885	44,014	(4,220)	85,672	(160,222)
Net cash (paid) received for scheduled derivative settlements	(17,622)	(37,431)	35,476	(54,204)	106,975
Other operating expenses	3,986	42	1,648	4,827	2,658
Impairment of oil and gas properties	—	—	—	—	289,085
Non-recurring costs	705	—	1,473	705	3,651
Total additions, net	2,954	6,625	34,377	37,000	242,147
Income tax (expense) benefit of adjustments at effective tax rate(1)	(1,254)	(37)	333	(1,765)	(51,152)
Adjusted Net Income (Loss)	$ 11,536	$ (6,293)	$ 13,452	$ 10,868	$ 36,236
Basic EPS on Adjusted Net Income (Loss)	$ 0.14	$ (0.08)	$ 0.17	$ 0.14	$ 0.45
Diluted EPS on Adjusted Net Income (Loss)	$ 0.14	$ (0.08)	$ 0.17	$ 0.13	$ 0.45
Weighted average shares of common stock outstanding - basic	80,242	80,471	79,879	80,277	79,776
Weighted average shares of common stock outstanding - diluted	82,898	80,471	80,062	82,715	79,958

(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 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, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
			(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
General and administrative expenses	$ 17,614	$ 16,065	$ 19,173	$ 50,749	$ 57,287
Subtract:					
Non-cash stock compensation expense (G&A portion)	(3,467)	(2,763)	(3,812)	(9,899)	(11,111)
Non-recurring costs	(705)	—	(1,473)	(705)	(3,651)
Adjusted general and administrative expenses	$ 13,442	$ 13,302	$ 13,888	$ 40,145	$ 42,525
Adjusted general and administrative expenses ($/boe)	$ 5.34	$ 5.35	$ 5.47	$ 5.40	$ 5.33

Liquidity and Capital Resources

Currently, we expect to fund our 2021 capital expenditures with cash flows from our operations. As of September 30, 2021, we had liquidity of $243 million, consisting of $43 million cash on hand and $200 million available for borrowings under our RBL Facility. The 2021 RBL Facility has an elected commitment of $200 million with no further borrowing restrictions beyond the covenants summarized below. We also have $400 million in aggregate principal amount 7% senior unsecured notes due February 2026 (the "2026 Notes") outstanding as further discussed below.

We currently believe that our liquidity, capital resources and cash on hand will be sufficient to conduct our business and operations for at least the next 12 months. We have hedged approximately 4,500 bbl/d at $52 per bbl for the remainder of 2021, 13,800 bbl/d at $60 per bbl in 2022, 11,400 bbl/d at $53 per bbl in 2023, and 6,500 bbl/d at $50 bbl in 2024. In the longer term, if oil prices were to significantly decline and remain weak, 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 until commodity prices recover. Please see Part II, Item 1A "Risk Factors" for a discussion of known material risks, many of which are beyond our control, that could adversely impact our business, liquidity, financial condition, and results of operations.

2021 RBL Facility

On August 26, 2021, we entered into a credit agreement that provided for a revolving loan with up to $500 million of commitment, subject to a reserve borrowing base ("2021 RBL Facility"). Our initial borrowing base and elected commitment is $200 million. The 2021 RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $20 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the 2021 RBL Facility on a dollar for dollar basis. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. Borrowing base redeterminations generally become effective each May and November, although the borrower and the lenders may each make one interim redetermination between scheduled redeterminations. The first scheduled redetermination is scheduled for November 2021.

If the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base at any time as a result of a redetermination of the borrowing base, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, deliver reserve engineering reports and mortgages covering additional oil and gas properties sufficient in certain lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the next six-month period. Upon certain adjustments to the borrowing base, we are required to make a lump sum payment in an amount equal to the amount by which the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the 2021 RBL Facility exceeds the borrowing base. In addition, the 2021 RBL Facility provides that if there are any outstanding borrowings and the consolidated cash balance exceeds $20 million at the end of each calendar week, such excess amounts shall be used to prepay borrowings under the credit agreement. Otherwise, any unpaid principal will be due at maturity.

The outstanding borrowings under the revolving loan bear interest at a rate equal to either (i) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% per annum, and (ii) a customary benchmark rate plus an applicable margin ranging from 3.0% to 4.0% per annum, and in each case depending on levels of borrowing base utilization. In addition, we must pay the lenders a quarterly commitment fee of 0.5% on the average daily unused amount of the borrowing availability under the 2021 RBL Facility. We have the right to prepay any borrowings under the 2021 RBL Facility with prior notice at any time without a prepayment penalty.

The 2021 RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a leverage ratio of not more than 3.0 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of September 30, 2021, our leverage ratio and current ratio were 2.1:1.0 and 2.4:1.0, respectively. In addition, the 2021 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 2021 RBL Facility as of September 30, 2021.

The 2021 RBL Facility contains usual and customary events of default and remedies for credit facilities of a similar nature. The 2021 RBL Facility also places restrictions on the borrower and its restricted subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of the borrower's senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters. For instance, the 2021 RBL Facility contains certain oil sales hedging requirements.

The 2021 RBL Facility permits us to repurchase equity and indebtedness, among other things, if availability is equal to or greater than 20% of the elected commitments or borrowing base, whichever is in effect, and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

Berry Corp. and its existing subsidiaries (other than Berry LLC (who is the borrower), C&J Management and C&J Well Services) guarantee, and each future subsidiary of Berry Corp., with certain exceptions, is required to guarantee, our obligations and obligations of the other guarantors under the 2021 RBL Facility and under certain hedging transactions and banking services arrangements (the "Guaranteed Obligations"). The lenders under the 2021 RBL Facility hold a mortgage on at least 90% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions.

As of September 30, 2021, we had no borrowings outstanding and approximately $200 million of available borrowings capacity under the 2021 RBL Facility.

2017 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 ("2017 RBL Facility"). In April 2021, we completed our scheduled semi-annual borrowing base redetermination under our 2017 RBL Facility, which resulted in a reaffirmed borrowing base and our elected commitment at $200 million. On August 26, 2021, we terminated the 2017 RBL Facility agreement. There were no borrowings outstanding at the time of termination.

Hedging

We have protected a significant portion of our anticipated cash flows in 2021, as well as a portion in 2022 through 2024, using our commodity hedging program, including swaps, puts and calls. 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. In addition, we also hedge to meet the hedging requirements of the 2021 RBL Facility. 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 current hedging positions. For information regarding risks related to our hedging program, see "Item 1A. Risk Factors—Risks Related to Our Operations and Industry" in our Annual Report.

As of September 30, 2021, we had the following crude oil production and gas purchases hedges.

	Q4 2021	FY 2022	FY 2023	FY 2024
Fixed Price Oil Swaps (Brent):				
Hedged volume (mbbls)	1,318	3,387	1,596	732
Weighted-average price ($/bbl)	$ 48.61	$ 66.63	$ 65.26	$ 61.78
Purchased Oil Put Options (Brent):				
Hedged volume (mbbls)	307	1,643	2,555	1,647
Weighted-average price ($/bbl)	$ 60.00	$ 50.00	$ 50.00	$ 50.00
Sold Oil Put Options (Brent):				
Hedged volume (mbbls)	—	1,643	2,555	1,647
Weighted-average price ($/bbl)	$ —	$ 40.00	$ 40.00	$ 40.00
Sold Oil Calls Options (Brent):				
Hedged volume (mbbls)	307	—	—	—
Weighted-average price ($/bbl)	$ 75.00	$ —	$ —	$ —
Purchased Gas Call Options (Henry Hub):				
Hedged volume (mmbtu)	1,830,000	10,950,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 4.00	$ 4.00	$ 4.00	$ 4.00
Sold Gas Put Options (Henry Hub):				
Hedged volume (mmbtu)	1,830,000	10,950,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 2.75	$ 2.75	$ 2.75	$ 2.75
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (mmbtu)	2,085,000	—	—	—
Weighted-average price ($/mmbtu)	$ 2.95	$ —	$ —	$ —

As of September 30, 2021 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 mmbtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period October 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of approximately $1 million. This gain will be cash settled in 2021 as the positions expire.

In October we added purchased gas put options (Henry Hub) of 20,000 mmbtu/d at $2.75 beginning November 2021 through March 2022, which offset the fourth quarter 2021 and first quarter 2022 sold gas put options included in the above table. We added sold oil put options (Brent) of 500 bbl/d at $60.00 beginning November 2021 through December 2021, which offset the fourth quarter 2021 purchased oil put options included in the above table. We also added purchased fixed price oil swaps (Brent) of 1,000 bbl/d at $66.95 beginning January 2022 through December 2022, which partially offset the 2022 fixed price oil swaps included in the table above.

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

	Three Months Ended			Nine Months Ended	
	September 30, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
Crude Oil (per bbl):					
Realized sales price, before the effects of derivative settlements	$ 69.01	$ 64.72	$ 39.88	$ 63.59	$ 39.00
Effects of derivative settlements	$ (14.66)	$ (18.33)	$ 16.28	$ (15.03)	$ 16.97
Oil with hedges ($/bbl)	$ 54.35	$ 46.39	$ 56.16	$ 48.56	$ 55.97
Purchased Natural Gas (per mmbtu):					
Purchase price, before the effects of derivative settlements	$ 5.79	$ 3.31	$ 2.69	$ 5.32	$ 2.25
Effects of derivative settlements	$ (2.30)	$ (0.31)	$ 0.10	$ (2.34)	$ 0.60
Purchased Natural Gas with hedges	$ 3.49	$ 3.00	$ 2.79	$ 2.98	$ 2.85

Pipeline Commitments

During the second and third quarters, we entered into pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California, that will reduce our expose to fuel gas purchase price fluctuations. During the third quarter we entered into a capacity agreement for approximately 32,700 mmbtu/d beginning May 2022 through April 2032 for a total commitment of $62 million. In the second quarter we entered into pipeline capacity agreements for approximately 10,000 mmbtu/d beginning October 2021 through October 2036 and approximately 5,500 mmbtu/d beginning November 2021 through December 2024 for a total commitment of $32 million. The average price for all three agreements is approximately $0.52 mmbtu/d.

Cash Dividends

Our Board of Directors approved a regular cash dividend of $0.04 per share on our common stock for each of the first and second quarters of 2021. We paid the first and the second quarter cash dividend in April and July 2021, respectively. The Board of Directors approved a $0.06 per share regular cash dividend on our common stock for each of the third and fourth quarters of 2021. We paid the third quarter dividend in October 2021 and the fourth quarter dividend is expected to be paid in January 2022. As of October 31, 2021, the Company has paid approximately $77 million in dividends since the inception of our dividend program in the third quarter of 2018. When combined with the $52 million in stock repurchases, this represents a 117% return of capital on our IPO net proceeds.

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 the time, they authorized repurchases of up to $50 million under the program. In 2018 and 2019, the Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in aggregate. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million available under the repurchase program. We did not repurchase any common stock in 2020. For the three and nine months ended September 30, 2021, we repurchased 471,022 shares at an average price of $5.18 per share for approximately $2 million, which is reflected as treasury stock. Accordingly, as of September 30, 2021, the Company has repurchased a total of 5,528,704 shares under the stock repurchase program for approximately $52 million in aggregate, leaving approximately $48 million authorized and available for future repurchases under the 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.

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 do 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 and is subject to a passive holding company covenant under the 2021 RBL Facility. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. 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 restrictions under the 2021 RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

The 2021 RBL Facility permits Berry Corp. to make dividends so long as both before and after giving pro forma effect to such distribution, no default or event of defaults exists, availability exceeds 20% of the elected commitments or borrowing base, whichever is in effect, and Berry Corp. demonstrates a pro forma leverage ratio less than or equal to 2.0 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,	
	2021	**2020**
	(in thousands)	
Net cash:		
Provided by operating activities	$ 82,258	$ 144,419
Used in investing activities	(110,536)	(74,522)
Used in financing activities	(14,118)	(22,277)
Net (decrease) increase in cash and cash equivalents	$ (42,396)	$ 47,620

Operating Activities

Cash provided by operating activities decreased for the nine months ended September 30, 2021 by approximately $62 million when compared to the nine months ended September 30, 2020, and the most significant decreases consisted of a $161 million change in derivatives settlements, an increase of $42 million in unhedged operating expenses and a decrease of $28 million in working capital changes and other. These cash decreases were partially offset by increased sales of $169 million.

Investing Activities

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

	Nine Months Ended September 30,	
	2021	2020
	(in thousands)	
Capital expenditures:		
Capital expenditures	$ (105,046)	$ (62,321)
Changes in capital expenditures accruals	5,299	(10,347)
Acquisition of properties and equipment and other	(11,649)	(2,104)
Proceeds from sale of properties and equipment and other	860	250
Cash used in investing activities	$ (110,536)	$ (74,522)

Cash used in investing activities increased $36 million for the nine months ended September 30, 2021 when compared to the same period in 2020, primarily due to an increase in cash used for capital spending. In 2021, we reinstated our development program, albeit at a lower level than we began 2020. In 2021, we also had approximately $10 million more in expenditures for acquisitions than we did in 2020.

Financing Activities

Cash used by financing activities decreased $8 million for the nine months ended September 30, 2021 when compared to the same period in 2020. In 2021, the cash used was primarily for dividends paid of $7 million and debt issuance cost write-off related to the 2017 RBL Facility of $3 million. In 2020, the cash used was primarily for dividends paid of $19 million.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2020 to September 30, 2021 are discussed below.

	September 30, 2021	December 31, 2020
	(in thousands)	
Cash and cash equivalents	$ 38,161	$ 80,557
Accounts receivable, net	$ 69,315	$ 52,027
Derivative instruments assets - current and long-term	$ 2,926	$ 2,507
Other current assets	$ 70,559	$ 19,400
Property, plant & equipment, net	$ 1,233,223	$ 1,258,084
Other noncurrent assets	$ 15,782	$ 7,235
Accounts payable and accrued expenses	$ 154,591	$ 151,985
Derivative instruments liabilities - current and long-term	$ 55,070	$ 23,321
Long-term debt	$ 394,285	$ 393,480
Deferred income taxes liability - long-term	$ —	$ 1,011
Asset retirement obligations - long-term	$ 115,458	$ 135,192
Other noncurrent liabilities	$ 25,666	$ 785
Stockholders’ equity	$ 684,896	$ 714,036

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

The $17 million increase in accounts receivable was driven by $23 million higher sales period-over-period, partially offset by $6 million lower hedge settlements outstanding at each period-end.

The $31 million increase in net derivative liabilities is due to the change from a net liability of $21 million at December 31, 2020 to a net liability of $52 million as of September 30, 2021. Changes to mark-to-market derivative values at the end of each period result from differences in the forward curve prices relative to the contract fixed prices, changes in positions held and settlements received and paid throughout the periods.

The $51 million increase in other current assets was primarily due to a $32 million reclassification to assets held for sale related to the pending divestiture of the Placerita Field, $7 million of prepayments for development permits, $7 million for deposits in support of letters of credit and $7 million for other prepaid fees, partially offset by a decrease in materials inventory of $2 million.

The $25 million decrease in property, plant and equipment was primarily due to year to date depreciation of $97 million and a $35 million reclassification to other current assets (assets held for sale) for the Placerita Field divestiture offset by $102 million in capital investments and $5 million in other items.

The $9 million increase in other noncurrent assets was due to $10 million of costs paid to escrow for the C&J Acquisition offset partially offset by $2 million unamortized debt issuance costs expensed for the termination of the 2017 RBL facility.

The $3 million increase in accounts payable and accrued expenses included approximately $20 million increase in asset retirement obligations due to a reclass from long term to short term related to assets held for sale, offset by a $5 million change from short-term to long-term liabilities due to changes in anticipated spending, $8 million of increased derivative settlement payables, $5 million in increased taxes, other than income taxes, a $5 million increase in capital spending, a $5 million increase for dividends accrued and a $5 million increase in royalties accrued due to increased sales. The increases were partially offset by a $36 million decrease in the current portion of the greenhouse gas liability, as well as a $4 million decrease due to bonus payments, net of accruals added.

The decrease of $20 million in the long-term portion of the asset retirement obligations from $135 million at December 31, 2020 to $115 million at September 30, 2021 was due to a $20 million reclassification of long-term to current liabilities related to assets held for sale, $12 million of liabilities settled during the period, and a $2 million reduction due to property sales. These decreases were partially offset by $8 million of accretion, a $5 million change from short-term to long-term liabilities due to changes in anticipated spending and $1 million of liabilities incurred.

The $25 million increase in other noncurrent liabilities was driven by additional non-current greenhouse gas liabilities compared to year end. At year-end 2020, the non-current portion of greenhouse gas liabilities was moved to current as the payments are due in 2021.

The $29 million decrease in stockholders' equity was due to the net loss of $24 million, $11 million of common stock dividends declared, $2 million of treasury stock and $1 million of shares withheld for payment of taxes on equity awards. These decreases were partially offset by $10 million of stock-based equity awards, net of taxes.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiaries, 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 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, 2021 and we did not record a material balance at December 31, 2020. 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 accruals on our balance sheet would not be material to our consolidated financial position or results of operations.

We, or our subsidiaries, 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, 2021, 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 continue to defend the matter vigorously, however, given the uncertainty of litigation and the stage of the case, among other things, at this time we cannot estimate the likelihood or an amount of possible loss, that may result from this action.

During the second and third quarters of 2021 we entered into pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California, that will reduce our expose to fuel gas purchase price fluctuations. During the third quarter of 2021 we entered into a capacity agreement for approximately 32,700 mmbtu/d beginning May 2022 through April 2032 for a total commitment of $62 million. In the second quarter of 2021 we entered into pipeline capacity agreements for approximately 10,000 mmbtu/d beginning October 2021 through October 2036 and approximately 5,500 mmbtu/d beginning November 2021 through December 2024 for a total commitment of $32 million.

Securities Litigation Matter

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (the “Defendants”). The complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company’s business, operational efficiency and stability, and compliance policies, that artificially inflated the Company’s stock price, resulting in injury to the purported class members when the value of Berry Corp.’s common stock declined following release of its financial results for the third quarter of 2020.

On January 21, 2021, motions were filed in the Torres Lawsuit as plaintiffs sought to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, alleging, among other things, that the Company and the individual defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company’s permits and permitting processes. The amended complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys’ fees and costs. The defendants’ motion to dismiss the amended complaint is due January 10, 2022. All briefing on the motion to dismiss will be completed by May 2, 2022, and no oral argument has yet been scheduled.

We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of September 30, 2021:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Off-Balance Sheet arrangements:					
Processing and transportation contracts[1]	$ 98,446	$ 8,292	$ 20,084	$ 16,429	$ 53,641
Operating lease obligations	9,825	1,985	3,411	3,103	1,326
Other purchase obligations[2]	24,900	7,800	17,100	—	—
Total contractual obligations	$ 133,171	$ 18,077	$ 40,595	$ 19,532	$ 54,967

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

(2) Amounts include a purchase commitment of $6 million to build a road, which is classified as current. Additionally, we have a drilling commitment in California, for which we are required to drill 97 wells with an estimated total cost of $29 million by April 2023. As of September 30, 2021 we have drilled 34 wells and are required to drill 6 additional wells estimated at $1.8 million by the end of December 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 and Part II, Item 7 “Critical Accounting Policies and Estimates” in the 2020 Annual Report on Form 10-K.

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 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 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;
- 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;
- concerns about climate change and other air quality issues;
- 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;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines;

- 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

As of September 30, 2021, there have been 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 2020 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 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 gas sales and natural gas purchase 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, 2021, the fair value of our hedge positions was a net liability of approximately $52 million. A 10% increase in the oil and natural gas index prices above the September 30, 2021 prices would result in a net liability of approximately $190 million; conversely, a 10% decrease in the oil and natural gas index prices below the September 30, 2021 prices would result in a net asset of approximately $2 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. Additionally, we cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our cash flows could be negatively impacted.

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, 2021.

There were no changes in the Company's internal control over financial reporting during the third quarter of 2021 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

We are involved in various legal and administrative proceedings in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

Securities Litigation Matter

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Torres Lawsuit") in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (the "Defendants"). The complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company's business, operational efficiency and stability, and compliance policies, that artificially inflated the Company's stock price, resulting in injury to the purported class members when the value of Berry Corp.'s common stock declined following release of its financial results for the third quarter of 2020.

On January 21, 2021, motions were filed in the Torres Lawsuit as plaintiffs sought to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, alleging, among other things, that the Company and the individual defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company's permits and permitting processes. The amended complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys' fees and costs. The defendants' motion to dismiss the amended complaint is due January 10, 2022. All briefing on the motion to dismiss will be completed by May 2, 2022, and no oral argument has yet been scheduled.

We dispute these claims and intend to defend the matter vigorously. Given the uncertainty of litigation, the preliminary stage of the case, and the legal standards that must be met for, among other things, class certification and success on the merits, we cannot reasonably estimate the possible loss or range of loss that may result from this action.

Other Matters.

For additional 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, 2020 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:

Our results could suffer if we are unable to successfully integrate and manage acquired businesses.

Our business could suffer if we are unable to successfully integrate acquired companies into our business, and to the extent that we make strategic investments or acquisitions in new geographic markets or businesses, undertake other related strategic initiatives or enter into a new line of business, we may face numerous risks and uncertainties, including risks associated with the following:

- the required investment of capital and other resources;

- the possibility that we have insufficient expertise to engage in such activities profitably or without incurring inappropriate amounts of risk;
- the diversion of management’s attention from our core businesses;
- assumption of liabilities in any acquired business;
- the disruption of our ongoing business; and
- the increasing demands on or issues related to the combination or integration of operational and management systems and controls. Entry into certain lines of business may subject us to new laws and regulations with which we are not familiar, and may lead to increased liability, litigation, regulatory risk and expense. If a new business generates insufficient revenue or if we are unable to efficiently manage our expanded operations, our operations and financial results may be adversely affected.

In addition, even if we are able to integrate acquired businesses successfully, we may not realize the full benefits of the cost efficiency or synergies, or other benefits that we anticipated when selecting our acquisition candidates or these benefits may not be achieved within a reasonable period of time. We may be required to invest significant capital and resources after an acquisition to maintain or grow the business that we acquire. Further, acquired businesses may not achieve anticipated revenues, earnings, or cash flows. Any shortfall in anticipated revenues, earnings, or cash flows could require us to write down the carrying value of the intangible assets associated with any acquired company, which would adversely affect our reported earnings.

As disclosed in, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, on October 1, 2021, we acquired the California operations of Basic Energy Services, Inc. (“Basic”), which includes well servicing, specialized completion and remedial services, and water logistics services business lines. The acquisition and establishment of this new business, operates as C&J Well Services, is expected to provide additional in-house capabilities for well servicing, including workovers and plugging and abandonment, and to create a strategic growth opportunity, including through helping the State of California properly plug and decommission the significant portfolio of orphan and idle wells in California. We do not have prior experience directly providing these services and it is possible that we have insufficient expertise to engage in such activities profitably or without incurring inappropriate amounts of risk, among the other risks noted above. If we unable to successfully operate this business, this may adversely impact our investment in the new line of business and our future growth plans for the business and may not allow us to realize the strategic rationale for this acquisition.

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 the time, they authorized repurchases of up to $50 million under the program. In 2018 and 2019, the Company repurchased a total of 5,057,682 shares under the stock repurchase program for approximately $50 million in aggregate. In February 2020, the Board of Directors authorized the repurchase of the remaining $50 million available under the repurchase program. We did not repurchase any common stock in 2020. For the three and nine months ended September 30, 2021, we repurchased 471,022 shares at an average price of $5.18 per share for approximately $2 million, which is reflected as treasury stock. Accordingly, as of September 30, 2021, the Company has repurchased a total of 5,528,704 shares under the stock repurchase program for approximately $52 million in aggregate, leaving approximately $48 million authorized and available for future repurchases under the 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.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares tha May Yet Be Purchased Under the Plan
July 1 - 31, 2021	—	$ —	—	$ —
August 1 - 31, 2021	471,022	$ 5.18	471,022	$ 47,564,0
September 1 - 30, 2021	—	$ —	—	$ —
Total	471,022	$ —	471,022	$ 47,564,0

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	Credit Agreement dated as of August 26, 2021, by and among Berry Corporation (bry), as a guarantor, together with Berry Petroleum Company, LLC, as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and as an issuing bank, and the lenders from time-to-time party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed on August 27, 2021)
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
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

(*) 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 and infrequent items.

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

"*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 and infrequent 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.

"b*oe*" 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.

"b*oe/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.

"*Fugitive Emissions*" means accidental emissions of vapors or gases from pressurized containment, either due to faulty equipment, leakage or other unforeseen mishaps.

"*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.

"*mm*bbl" 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.

"*OPEC*" is an abbreviation for the Organization of the Petroleum Exporting Countries.

"*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.

"*Unconventional resource plays*" means a resource play that uses methods other than traditional vertical well extraction. Unconventional resources are trapped in reservoirs with low permeability, meaning little to no ability for the oil or natural gas to flow through the rock and into a wellbore. Examples of unconventional oil resources include oil shales, oil sands, extra-heavy oil, gas-to-liquids and coal-to-liquids.

"*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 3, 2021	*/s/* Cary Baetz
		Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	November 3, 2021	*/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 3, 2021

/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 3, 2021

/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, 2021, as filed with the Securities and Exchange Commission on November 3, 2021 (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 3, 2021

/s/ A. T. Smith

A. T. "Trem" Smith
President and Chief Executive Officer

Date: November 3, 2021

/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.