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, 2023
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 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See 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, 2023 75,666,776

Table of Contents

			Page
Part I – Financial Information			
Item 1.	Financial Statements (unaudited)		
		Condensed Consolidated Balance Sheets	1
		Condensed Consolidated Statements of Operations	2
		Condensed Consolidated Statements of Stockholders' Equity	3
		Condensed Consolidated Statements of Cash Flows	5
		Notes to Condensed Consolidated Financial Statements	6
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations		23
Item 3.	Quantitative and Qualitative Disclosures About Market Risk		70
Item 4.	Controls and Procedures		71
Part II – Other Information			
Item 1.	Legal Proceedings		72
Item 1A.	Risk Factors		73
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds and Issuer Purchases of Equity Securities		74
Item 5.	Other Information		75
Item 6.	Exhibits		76
	Glossary of Terms		77
	Signatures		84

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, 2023	December 31, 2022
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 17,200	$ 46,250
Accounts receivable, net of allowance for doubtful accounts of $866 at September 30, 2023 and December 31, 2022	102,794	101,713
Derivative instruments	—	36,367
Other current assets	37,697	33,725
Total current assets	157,691	218,055
Noncurrent assets:		
Oil and natural gas properties	1,854,359	1,725,864
Accumulated depletion and amortization	(559,437)	(465,889)
Total oil and natural gas properties, net	1,294,922	1,259,975
Other property and equipment	165,922	155,619
Accumulated depreciation	(70,301)	(55,781)
Total other property and equipment, net	95,621	99,838
Derivative instruments	—	76
Deferred income taxes	54,133	42,844
Other noncurrent assets	11,558	10,242
Total assets	$ 1,613,925	$ 1,631,030
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 173,900	$ 203,101
Derivative instruments	46,162	31,106
Total current liabilities	220,062	234,207
Noncurrent liabilities:		
Long-term debt	453,667	395,735
Derivative instruments	25,965	13,642
Asset retirement obligations	159,764	158,491
Other noncurrent liabilities	46,348	28,470
Commitments and Contingencies - Note 4		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 87,670,587 and 86,350,771 shares issued; and 75,666,776 and 75,767,503 shares outstanding, at September 30, 2023 and December 31, 2022, respectively)	88	86
Additional paid-in-capital	815,936	821,443
Treasury stock, at cost (12,003,811 and 10,583,268 shares at September 30, 2023 and December 31, 2022, respectively)	(113,768)	(103,739)
Retained earnings	5,863	82,695
Total stockholders' equity	708,119	800,485
Total liabilities and stockholders' equity	$ 1,613,925	$ 1,631,030

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,	
	2023	2022	2023	2022
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 172,611	$ 203,585	$ 496,671	$ 654,007
Services revenue	45,511	48,594	137,808	134,608
Electricity sales	3,849	9,711	12,372	22,549
(Losses) gains on oil and gas sales derivatives	(103,282)	114,279	(43,912)	(88,237)
Marketing revenues	—	—	—	289
Other revenues	113	277	194	442
Total revenues and other	118,802	376,446	603,133	723,658
Expenses and other:				
Lease operating expenses	59,842	79,141	249,384	214,720
Costs of services	35,806	37,628	108,988	107,809
Electricity generation expenses	1,479	6,055	5,252	16,640
Transportation expenses	1,089	1,277	3,226	3,543
Marketing expenses	—	—	—	299
Acquisition costs	2,082	—	3,054	—
General and administrative expenses	20,987	23,388	75,144	69,513
Depreciation, depletion, and amortization	39,729	39,506	119,605	117,338
Taxes, other than income taxes	17,980	7,335	42,147	25,154
(Gains) losses on natural gas purchase derivatives	(8,425)	(28,942)	4,989	(47,335)
Other operating (income) expenses	(505)	623	(1,824)	4,745
Total expenses and other	170,064	166,011	609,965	512,426
Other (expenses) income:				
Interest expense	(9,101)	(7,867)	(25,732)	(23,271)
Other, net	(42)	(24)	(227)	(79)
Total other expenses	(9,143)	(7,891)	(25,959)	(23,350)
(Loss) income before income taxes	(60,405)	202,544	(32,791)	187,882
Income tax (benefit) expense	(15,343)	10,884	(7,640)	9,678
Net (loss) income	$ (45,062)	$ 191,660	$ (25,151)	$ 178,204
Net (loss) income per share:				
Basic	$ (0.60)	$ 2.46	$ (0.33)	$ 2.25
Diluted	$ (0.60)	$ 2.34	$ (0.33)	$ 2.13

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, 2022				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	(in thousands)				
December 31, 2021	$ 86	$ 912,471	$ (52,436)	$ (167,473)	$ 692,648
Shares withheld for payment of taxes on equity awards and other	—	(4,096)	—	—	(4,096)
Stock based compensation	—	3,920	—	—	3,920
Dividends declared on common stock, $0.06/share	—	(5,236)	—	—	(5,236)
Net loss	—	—	—	(56,810)	(56,810)
March 31, 2022	86	907,059	(52,436)	(224,283)	630,426
Shares withheld for payment of taxes on equity awards and other	—	(6)	—	—	(6)
Stock based compensation	—	4,720	—	—	4,720
Purchases of treasury stock	—	—	(22,760)	—	(22,760)
Dividends declared on common stock, $0.19/share	—	(14,965)	—	—	(14,965)
Net income	—	—	—	43,354	43,354
June 30, 2022	86	896,808	(75,196)	(180,929)	640,769
Shares withheld for payment of taxes on equity awards and other	—	(34)	—	—	(34)
Stock based compensation	—	4,625	—	—	4,625
Purchases of treasury stock	—	—	(18,940)	—	(18,940)
Dividends declared on common stock, $0.62/share	—	(48,831)	—	—	(48,831)
Net income	—	—	—	191,660	191,660
September 30, 2022	$ 86	$ 852,568	$ (94,136)	$ 10,731	$ 769,249

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, 2023				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	(in thousands)				
December 31, 2022	$ 86	$ 821,443	$ (103,739)	$ 82,695	$ 800,485
Shares withheld for payment of taxes on equity awards and other	—	(4,260)	—	—	(4,260)
Stock based compensation	—	4,989	—	—	4,989
Issuance of common stock	2	—	—	—	2
Dividends declared on common stock, $0.50/share	—	—	—	(42,421)	(42,421)
Net loss	—	—	—	(5,859)	(5,859)
March 31, 2023	88	822,172	(103,739)	34,415	752,936
Shares withheld for payment of taxes on equity awards and other	—	(2,612)	—	—	(2,612)
Stock based compensation	—	3,770	—	—	3,770
Purchases of treasury stock	—	—	(10,029)	—	(10,029)
Dividends declared on common stock, $0.12/share	—	—	—	(9,260)	(9,260)
Net income	—	—	—	25,770	25,770
June 30, 2023	88	823,330	(113,768)	50,925	760,575
Shares withheld for payment of taxes on equity awards and other	—	(44)	—	—	(44)
Stock based compensation	—	3,243	—	—	3,243
Dividends declared on common stock, $0.14/share	—	(10,593)	—	—	(10,593)
Net loss	—	—	—	(45,062)	(45,062)
September 30, 2023	$ 88	$ 815,936	$ (113,768)	$ 5,863	$ 708,119

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,	
	2023	2022
	(in thousands)	
Cash flows from operating activities:		
Net (loss) income	$ (25,151)	$ 178,204
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	119,605	117,338
Amortization of debt issuance costs	1,952	1,531
Stock-based compensation expense	11,336	12,623
Deferred income taxes	(10,397)	6,211
Other operating expenses (income)	1,283	(120)
Derivative activities:		
Total losses	48,901	40,902
Cash settlements on derivatives	15,511	(84,519)
Changes in assets and liabilities:		
Decrease (increase) in accounts receivable	11,644	(7,334)
(Increase) decrease in other assets	(3,820)	2,320
Decrease in accounts payable and accrued expenses	(53,347)	(11,281)
Increase (decrease) in other liabilities	2,122	(341)
Net cash provided by operating activities	119,639	255,534
Cash flows from investing activities:		
Capital expenditures:		
Capital expenditures	(56,124)	(102,523)
Changes in capital expenditures accruals	(10,431)	14,129
Acquisitions, net of cash received	(59,895)	(21,270)
Net cash used in investing activities	(126,450)	(109,664)
Cash flows from financing activities:		
Borrowings under 2021 RBL credit facility	387,000	206,000
Repayments on 2021 RBL credit facility	(330,000)	(206,000)
Borrowings under 2022 ABL credit facility	—	2,067
Repayments on 2022 ABL credit facility	—	(2,067)
Dividends paid on common stock	(62,274)	(73,844)
Purchase of treasury stock	(10,029)	(41,700)
Shares withheld for payment of taxes on equity awards and other	(6,936)	(4,136)
Net cash used in financing activities	(22,239)	(119,680)
Net (decrease) increase in cash and cash equivalents	(29,050)	26,190
Cash and cash equivalents:		
Beginning	46,250	15,283
Ending	$ 17,200	$ 41,473

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”), (C&J Management and C&J together, “CJWS”). As the context may require, the “Company”, “we”, “our” or similar words refer to Berry Corp. and its subsidiaries, Berry LLC, C&J Management and C&J. In July 2023, we executed an agreement to acquire Macpherson Energy Corporation and its subsidiaries, a privately held Kern County, California operator, and we closed the acquisition in September 2023 (“Macpherson Acquisition”). As of September 15, 2023, Berry LLC owns Macpherson Energy, LLC (formerly, known as Macpherson Energy Corporation) and its subsidiaries (“Macpherson Energy”).

Nature of Business

We are a western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived oil and gas reserves. We operate in two business segments: (i) exploration and production (“E&P”) and (ii) well servicing and abandonment. Our E&P assets are located in California and the Rockies, characterized by high oil content and predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Rockies assets are in the Uinta basin of Utah (60% oil and 40% gas). We operate our well servicing and abandonment segment in California.

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. Securities 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, 2022.

Note 2—Debt

The following table summarizes our outstanding debt:

	September 30, 2023	December 31, 2022	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ 57,000	$ —	variable rates 10.75% (2023) and 9.50% (2022)	August 26, 2025	Mortgage on 90% of Present Value of proven oil and gas reserves and lien on certain other assets
2022 ABL Facility	—	—	variable rates 9.75% (2023) and 8.3% (2022)	June 5, 2025	CJWS property and certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	457,000	400,000			
Less: Debt Issuance Costs	(3,333)	(4,265)			
Long-Term Debt, net	$ 453,667	$ 395,735			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At September 30, 2023 and December 31, 2022, debt issuance costs reported in "other noncurrent assets" on the balance sheet were approximately (i) $3 million and $4 million, respectively, net of amortization, for the Credit Agreement, dated as of August 26, 2021, among Berry Corp, as a guarantor, Berry LLC, as the borrower, JPMorgan Chase Bank, N.A., as the administrative agent and the other parties thereto (as amended, restated, modified or otherwise supplemented from time to time, the "2021 RBL Facility") and (ii) an immaterial amount, net of amortization, for the Revolving Loan and Security Agreement, dated as of August 9, 2022, among C&J and C&J Management, as borrowers, and Tri Counties Bank, as lender (as amended, restated, supplemented or otherwise modified from time to time, the "2022 ABL Facility"). At September 30, 2023 and December 31, 2022, 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 was approximately $3 million and $4 million, respectively.

For each of the three month periods ended September 30, 2023 and 2022, the amortization expense for the 2021 RBL Facility, the 2022 ABL Facility and the 2026 Notes, combined, was approximately $1 million. For each of the nine month periods ended September 30, 2023 and 2022, the amortization expense for the 2021 RBL Facility, the 2022 ABL Facility and the 2026 Notes, combined, was approximately $2 million. The amortization of debt issuance costs is presented in "interest expense" on the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amounts of the 2021 RBL Facility and the 2022 ABL Facility approximate fair value because the interest rates are variable and reflect market rates. The 2021 RBL Facility and 2022 ABL Facility are Level 2 in the fair value hierarchy. The fair value of the 2026 Notes was approximately $384 million and $369 million at September 30, 2023 and December 31, 2022, respectively. The 2026 Notes are Level 1 in the fair value hierarchy.

2021 RBL Facility

The borrowing base under the 2021 RBL Facility is redetermined semi-annually, and the 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. On May 10, 2023, Berry Corp, as a guarantor, and Berry LLC, as borrower, entered into the Fourth Amendment to Credit Agreement (the "Amendment") pursuant to which, among other things, the requisite lenders under the 2021 RBL Facility agreed to (i) maintain the aggregate elected commitment amounts at $200 million, (ii) decrease the borrowing base from $250 million to $200 million, which constituted a redetermination of the borrowing base that was scheduled to occur on or about May 1, 2023 pursuant to the terms of the Credit Facility, (iii) decrease the maximum consolidated leverage ratio by 0.25x to 2.75x for fiscal quarters ending June 30, 2023 and thereafter and (iv) amend the minimum hedging covenant to specify the floor price set forth in the Amendment but without any modification to the minimum volumes required to be hedged.

As of September 30, 2023, the 2021 RBL Facility had a $500 million revolving commitment and the aforementioned $200 million borrowing base and aggregate elected commitment and a $20 million sublimit for the issuance of letters of credit (with borrowing availability being reduced by the face amount of any letters of credit issued under the subfacility). Availability under the 2021 RBL Facility may not exceed the lesser of the aggregate elected commitments or the borrowing base less outstanding advances and letters of credit. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. The 2021 RBL Facility is available to us for general corporate purposes, including working capital.

The outstanding borrowings under the 2021 RBL Facility bear interest at a rate equal to, at our option, either (a) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% or (b) a term SOFR reference rate, plus an applicable margin ranging from 3.0% to 4.0%, in each case determined based on the utilization level under the 2021 RBL Facility. Interest rate on base borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on term SOFR borrowings accrues in respect of interest periods of one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days and is payable on the last day of such interest period (or, for interest periods of six months, three months after the commencement of such interest period and at the end of such interest period). Unused commitment fees are charged at a rate of 0.50%.

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 2.75 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of September 30, 2023, we were in compliance with all of the debt covenants.

The 2021 RBL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If we do not comply with the financial and other covenants in the 2021 RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the 2021 RBL Facility and terminate the commitments thereunder.

As of September 30, 2023, we had $57 million borrowings outstanding, $10 million in letters of credit outstanding and approximately $133 million of available borrowing capacity under the 2021 RBL Facility. As of October 31, 2023, we reduced the borrowings to $49 million.

2022 ABL Facility

Subject to satisfaction of customary conditions precedent to borrowing, as of September 30, 2023, C&J and C&J Management could borrow up to the lesser of (x) $15 million and (y) the borrowing base under the 2022 ABL Facility, with a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $7.5 million (with borrowing availability being reduced by the face amount of any letters of credit issued under the subfacility). The "borrowing base" is an amount equal to 80% of the balance due on eligible accounts receivable, subject to reserves that the lender may implement in its reasonable discretion. As of September 30, 2023, the borrowing base was $15 million. Interest on the outstanding principal amount of the revolving loans under the 2022 ABL Facility accrues at a per annum rate equal to 1.25% in excess of The Wall Street Journal Prime Rate. The "Wall Street Journal Prime Rate" is the variable rate of interest, on a per annum basis, which is announced and/or published in the "Money Rates" section of The Wall Street Journal from time to time as its "Prime Rate". The rate will be redetermined whenever The Wall Street Journal Prime Rate changes. Interest is due quarterly, in arrears. The 2022 ABL Facility matures on June 5, 2025, unless terminated in accordance with the 2022 ABL Facility terms.

The 2022 ABL Facility requires CJWS to comply with the following financial covenants (i) maintain on a consolidated basis a ratio of total liabilities to tangible net worth of no greater than 1.5 to 1.0 at any time; (ii) reduce the amount of revolving advances outstanding under the 2022 ABL Facility to not more than 90% of the lesser of (a) the maximum revolving advance amount or (b) the borrowing base, as of the lender's close of business on the last day of each fiscal quarter; and (iii) maintain net income before taxes of not less than $1.00 as of each fiscal year end. As of September 30, 2023, CJWS was in compliance with all of the debt covenants.

The 2022 ABL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If CJWS does not comply with the financial and other covenants in the 2022 ABL Facility, the lender may, subject to customary cure rights, require immediate payment of all amounts outstanding under the 2022 ABL Facility and terminate the commitment thereunder. CJWS's obligations under the 2022 ABL Facility are not guaranteed by Berry Corp. or Berry LLC and Berry Corp. and Berry LLC do not and are not required to provide any credit support for such obligations.

In March 2023, we entered into the Amendment to Revolving Loan and Security Agreement (the "First Amendment"). The First Amendment, in addition to other changes described therein, amended the 2022 ABL Facility to substitute certain collateral.

As of September 30, 2023, CJWS had no borrowings and $2 million letters of credit outstanding with $13 million of available borrowing capacity under the 2022 ABL Facility.

Senior Unsecured Notes

In February 2018, Berry LLC completed a private issuance of $400 million in aggregate principal amount of 7.0% senior unsecured notes due February 2026, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers' discount.

The 2026 Notes are Berry LLC's senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. The 2026 Notes are fully and unconditionally guaranteed on a senior unsecured basis by Berry Corp.

The indenture governing the 2026 Notes contains customary covenants and events of default (in some cases, subject to grace periods). We were in compliance with all covenants under the 2026 Notes as of September 30, 2023.

Debt Repurchase Program

In February 2020, the board of directors (the "Board of Directors" or the "Board") 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 notes under this program.

Note 3—Derivatives

We utilize derivatives, such as swaps, puts, calls and collars, 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 satisfying the oil 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 three 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. We had no such transactions in the periods presented.

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 bbl and per mmbtu, respectively, and receive settlement payments for prices below the indicated weighted-average price per bbl and per mmbtu, respectively.

For our sold call options, we would make settlement payments for prices above the indicated weighted-average price per barrel, net of any deferred premium. No payment would be made or received for prices below the indicated weighted-average price per barrel, other than any applicable deferred premium.

For our purchased puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel, net of any deferred premium. No payment would be made or received for prices above the indicated weighted-average price per barrel, other than any applicable deferred premium.

For our sold puts, we would make settlement payments for prices below the indicated weighted-average price per barrel, net of any deferred premium. No payment would be made or received for prices above the indicated weighted-average price per barrel, other than any applicable deferred premium.

For natural gas basis swaps, we make settlement payments if the difference between NWPL and Henry Hub is below the indicated weighted-average price of our contracts and receive settlement payments if the difference between NWPL and Henry Hub is above the indicated weighted-average price.

For some of our options we paid or received a premium at the time the positions were created and for others, the premium payment or receipt is deferred until the time of settlement. As of September 30, 2023, we have net payable deferred premiums of approximately $2 million, which is reflected in the mark-to-market valuation and will be payable through December 31, 2024.

We use oil and gas production hedges to protect our sales against decreases in oil and gas prices. We also use natural gas purchase hedges 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, 2023, we had the following crude oil production and gas purchases hedges.

	Q4 2023	FY 2024	FY 2025	FY 2026
Brent - Crude Oil production				
Swaps				
Hedged volume (bbls)	1,407,600	5,426,817	1,847,125	645,768
Weighted-average price ($/bbl)	$ 77.61	$ 77.82	$ 75.21	$ 69.43
Sold Calls[1]				
Hedged volume (bbls)	368,000	732,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 106.00	$ 105.00	$ 91.11	$ 85.53
Purchased Puts (net)[2]				
Hedged volume (bbls)	552,000	1,281,000	365,000	—
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ 50.00	$ —
Purchased Puts (net)[2]				
Hedged volume (bbls)	—	—	2,121,127	1,251,500
Weighted-average price ($/bbl)	$ —	$ —	$ 60.00	$ 60.00
Sold Puts (net)[2]				
Hedged volume (bbls)	154,116	183,000	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ —	$ —
Henry Hub - Natural Gas purchases				
NWPL - Natural Gas purchases				
Swaps				
Hedged volume (mmbtu)	3,680,000	10,980,000	6,080,000	—
Weighted-average price ($/mmbtu)	$ 5.34	$ 4.21	$ 4.27	$ —
Gas Basis Differentials				
NWPL/HH - basis swaps				
Hedged volume (mmbtu)	610,000	—	—	—
Weighted-average price ($/mmbtu)	$ 1.12	$ —	$ —	$ —

(1) Purchased calls and sold calls with the same strike price have been presented on a net basis.

(2) Purchased puts and sold puts with the same strike price have been presented on a net basis.

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, 2023 and December 31, 2022:

	September 30, 2023			
	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	$ 12,494	$ (12,494)	$ —
Commodity Contracts	Non-current assets	25,339	(25,339)	—
Liabilities:				
Commodity Contracts	Current liabilities	(58,656)	12,494	(46,162)
Commodity Contracts	Non-current liabilities	(51,304)	25,339	(25,965)
Total derivatives		$ (72,127)	$ —	$ (72,127)

	December 31, 2022			
	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	$ 66,974	$ (30,607)	$ 36,367
Commodity Contracts	Non-current assets	39,886	(39,810)	76
Liabilities:				
Commodity Contracts	Current liabilities	(61,713)	30,607	(31,106)
Commodity Contracts	Non-current liabilities	(53,452)	39,810	(13,642)
Total derivatives		$ (8,305)	$ —	$ (8,305)

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 Standard & 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, 2023 and December 31, 2022. 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, 2023, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matters

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Securities Class Action”) 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 (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933 (as amended, the “Securities Act”), and Sections 10(b) and 20(a) of the Exchange Act of 1934 (as amended, the “Exchange Act”), on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company’s 2018 IPO; or (ii) Berry Corp.’s securities between July 26, 2018 and November 3, 2020 (the “Class Period”). In particular, 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 November 3, 2020.

On November 1, 2021, the court-appointed 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 and Sections 10(b) and 20(a) of the Exchange Act, 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 filed a motion to dismiss on January 24, 2022 and on September 13, 2022, the court issued an order denying that motion, and the case moved into discovery. On February 13, 2023, the plaintiffs filed a motion for class certification, and on April 14, 2023, the defendants filed their opposition; the plaintiffs filed their reply on May 26, 2023, and a hearing on the motion for class certification was set for August 23, 2023.

On July 31, 2023, the parties executed a Memorandum of Understanding memorializing an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. On September 18, 2023, the plaintiffs and Defendants executed a Stipulation and Agreement of Settlement, and the plaintiffs filed a motion seeking preliminary approval of the settlement. On October 18, 2023, the Court granted that motion, issuing a preliminary approval order and scheduling a final settlement approval hearing for February 6, 2024. The parties will now move forward with the notice and approval process, which is expected to include, among other things, the February 6, 2024 final approval hearing, an opt-out process, and opportunities for class members to object to the settlement. The Defendants continue to maintain that the claims are without merit and admit no liability in connection with the settlement.

On October 20, 2022, a shareholder derivative lawsuit (the “Assad Lawsuit”) was filed in the United States District Court for the Northern District of Texas by putative stockholder George Assad, allegedly on behalf of the Company, that piggy-backs on the Securities Class Action and which is currently pending before the same court. The derivative complaint names certain current and former officers and directors as defendants, and generally alleges that they breached their fiduciary duties by causing or failing to prevent the securities violations alleged in the securities class action. The derivative complaint also alleges claims for unjust enrichment as against all defendants, and claims for contribution and indemnification under Sections 10(b) and 21D of the Exchange Act. On January 27, 2023, the court granted the parties’ joint stipulated request to stay the Assad Lawsuit pending resolution of the Securities Class Action.

On January 20, 2023, a second shareholder derivative lawsuit (the “Karp Lawsuit,” together with the Assad Lawsuit, the “Shareholder Derivative Actions”) was filed, this time in the United States District Court for the District of Delaware, by putative stockholder Molly Karp, allegedly on behalf of the Company, again piggy-backing on the Securities Class Action. This complaint, similar to the Assad Lawsuit, is brought against certain current and former officers and directors of the Company, asserting breach of fiduciary duty, aiding and abetting, and contribution claims based on the defendants allegedly having caused or failed to prevent the securities violations alleged in the securities class action. In addition, the complaint asserts a claim under Section 14(a) of the Exchange Act, alleging that Berry’s 2022 proxy statement was false and misleading in that it suggested the Company’s internal controls were sufficient and the Board of Directors was adequately overseeing material risks facing the Company when, according to the derivative plaintiff, that was not the case. On February 13, 2023, the court granted the parties’ joint stipulated request to stay the Karp Lawsuit pending resolution of a motion for summary judgment by the defendants in the Securities Class Action. The proposed settlement of the Securities Class Action does not relate to the Shareholder Derivative Actions. The defendants continue to believe the claims in the Shareholder Derivative Actions are without merit and intend to defend vigorously against them, but there can be no assurances as to the outcome. At this time, we are unable to estimate the probability or the amount of liability, if any, related to these matters.

In addition, on or around April 17, 2023, the Company received a stockholder litigation demand that the Board of Directors investigate and commence legal proceedings against certain current and former officers and directors based ostensibly on the same claims asserted in the Shareholder Derivative Actions. The Board of Directors appointed a Demand Review Committee for the purpose of reviewing the demand.

Note 5—Equity

Cash Dividends

In February 2023, the Board of Directors declared regular fixed cash dividends of $0.06 per share, as well as variable cash dividends of $0.44 per share which was based on the results of the fourth quarter of 2022, for a total of $0.50 per share, which was paid in March 2023. In April 2023, the Board of Directors declared a $0.12 per share regular fixed cash dividend based on the results of the first quarter of 2023, which was paid in May 2023. In July 2023, the Board of Directors declared a $0.12 per share regular fixed cash dividend, as well as a variable dividend of $0.02 based on the results for the six months ended June 30, 2023, which was paid in August 2023. In October 2023, the Board of Directors approved a $0.12 per share regular fixed cash dividend, as well as a variable dividend of $0.09 based on the results of the third quarter of 2023, each of which is expected to be paid in November 2023.

The Company anticipates that it will continue to pay quarterly cash dividends in the future. However, the payment and amount of future dividends remain within the discretion of the Board and will depend upon the Company’s future earnings, financial condition, capital requirements, and other factors.

Stock Repurchase Program

The Company did not repurchase any shares during the three months ended September 30, 2023. For the nine months ended September 30, 2023, we repurchased 1.4 million shares (all in the second quarter) for approximately $10 million.

As of September 30, 2023, the Company had repurchased a total of 11,949,247 shares under the stock repurchase program for approximately $114 million in aggregate. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company intends to allocate a portion of Adjusted Free Cash Flow to opportunistic share repurchases.

In February 2023, the Board of Directors approved an increase of $102 million to the Company's stock repurchase authorization bringing the Company's remaining share authority to $200 million. As of September 30, 2023, the Company's remaining total share repurchase authority is $190 million. The Board's authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions, subject to market conditions and other factors, up to the aggregate amount authorized by the Board. The Board's authorization has no expiration date.

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. Purchases may be commenced or suspended at any time without notice and do not obligate the company to purchase shares during any period or at all. Any shares repurchased are reflected as treasury stock and any shares acquired will be available for general corporate purposes.

Stock-Based Compensation

In February 2023, the Company granted awards of approximately 1,031,000 shares of restricted stock units ("RSUs"), which will vest annually in equal amounts over three years and a target number of approximately 437,000 shares of 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 2023 are solely time-based awards. Of the PSUs awarded to certain Berry employees (excluding CJWS employee awards) in February 2023, (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 (b) 50% of such awards will vest, if at all, based on the consolidated Company's average cash returned on invested capital ("CROIC PSUs") over the performance period. The PSUs awarded to certain CJWS employees in February 2023 will vest, if at all, based on the CJWS average cash returned on invested capital ("ROIC 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 200% of the target TSR, CROIC and ROIC PSUs granted.

The fair value of the RSUs, CROIC PSUs and ROIC 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 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, 2023	December 31, 2022
	(in thousands)	
Prepaid expenses	$ 9,970	$ 12,330
Materials and supplies	16,591	8,976
Deposits	7,087	7,266
Oil inventories	3,824	4,036
Other	225	1,117
Total other current assets	$ 37,697	$ 33,725

Other non-current assets at September 30, 2023 included approximately $8 million of operating lease right-of-use assets, net of amortization and $3 million of deferred financing costs, net of amortization. At December 31, 2022, other non-current assets included approximately $6 million of operating lease right-of-use assets, net of amortization and $4 million of deferred financing costs, net of amortization.

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

	September 30, 2023	December 31, 2022
	(in thousands)	
Accounts payable-trade	$ 43,027	$ 40,286
Deferred acquisition payable(1)	18,499	—
Accrued expenses	48,852	85,360
Royalties payable	24,047	38,264
Taxes other than income tax liability	11,555	6,640
Accrued interest	5,070	10,885
Asset retirement obligations - current portion	20,000	20,000
Operating lease liability	2,850	1,666
Total accounts payable and accrued expenses	$ 173,900	$ 203,101

(1) Relates to the remaining payable of $20 million, on a discounted basis, for the Macpherson Acquisition due in July 2024.

The increase of approximately $1 million in the long-term portion of the asset retirement obligations from $158 million at December 31, 2022 to $160 million at September 30, 2023 was due to $9 million of accretion and a $7 million increase of asset retirement obligations for Macpherson Energy, largely offset by $15 million of liabilities settled during the period.

Other noncurrent liabilities at September 30, 2023 included approximately $40 million of greenhouse gas liability, which is due in the fourth quarter of 2024, and $6 million of operating lease noncurrent liability. At December 31, 2022, other non-current liabilities included approximately $23 million non-current greenhouse gas liability, which is due in the fourth quarter of 2024, and $5 million of non-current operating lease liability.

Supplemental Information on the Statement of Operations

For the nine months ended September 30, 2023, other operating income was $2 million and mainly consisted of net property tax refunds from prior periods and a net gain on equipment sales. For the nine months ended September 30, 2022, other operating expenses were $5 million and mainly consisted of over $2 million in royalty audit charges incurred prior to our emergence and restructuring in 2017, and approximately $2 million loss on the divestiture of the Piceance properties.

Supplemental Cash Flow Information

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

	Nine Months Ended September 30,	
	2023	2022
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Deferred consideration payable for acquisition	$ 18,499	$ —
Material inventory transfers to oil and natural gas properties	$ 1,300	$ 1,494
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 30,457	$ 29,481
Income taxes payments	$ 2,757	$ 2,805

Note 7—Acquisition and Divestiture

Macpherson Acquisition

In July 2023, we executed an agreement to acquire Macpherson Energy, a privately held Kern County, California operator and we closed the acquisition in September 2023. The total purchase price is approximately $70 million, subject to customary purchase price adjustments. The transaction was structured such that approximately $53 million has been paid at closing, including purchase price adjustments, and approximately $20 million will be paid in July 2024, subject to purchase price adjustments.

The Macpherson transaction was accounted for as a business combination under the acquisition method of accounting. When determining the fair values of assets acquired and liabilities assumed, management made significant estimates, judgments and assumptions. The assets acquired and liabilities assumed are included in the E&P segment. The Company's preliminary allocation of the purchase price as of the closing date, including preliminary working capital adjustments, to the estimated fair value of the Macpherson Energy net assets is as follows:

		September 15, 2023
		(in thousands)
Cash and cash equivalents	$	3,845
Accounts receivable, net of allowance for doubtful accounts		12,694
Other current assets		1,541
Property and equipment		76,472
Other noncurrent assets		1,865
Total assets acquired	$	96,417
Accounts payable and accrued expenses assumed		(15,502)
Asset retirement obligation		(7,422)
Other noncurrent liabilities		(434)
Net assets acquired	$	73,059

The allocation of the purchase price to Macpherson Energy net tangible assets and liabilities as of September 15, 2023, is preliminary and subject to revisions to the fair value calculations for the identifiable assets and liabilities. The final purchase price allocation could differ from the preliminary allocation noted in the summary above. The acquired property and equipment is stated at fair value, and amortization on the acquired oil and gas property is computed using units-of-production method over the remaining proved reserves and depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of each asset.

The unaudited pro forma information presented below has been prepared to give effect to the Macpherson Acquisition as if it had occurred at the beginning of the periods presented. The unaudited pro forma information includes the effects from the allocation of the acquisition purchase price on depreciation and amortization as well as the Macpherson Acquisition costs charged to earnings during the nine months ended September 30, 2023 and 2022. The unaudited pro forma information is presented for illustration purposes only and is based on estimates and assumptions the Company deemed appropriate. The following unaudited pro forma information is not necessarily indicative of the results that would have been achieved if the Macpherson Acquisition had occurred in the past, and should not be relied upon as an indication of the operating results that the Company would have achieved if the acquisition had occurred at the beginning of the periods presented, and our operating results, or the future results.

	Pro Forma Nine Months Ended September 30,			
	2023		2022	
	(unaudited) (in thousands)			
Revenue	$	642,054	$	803,005
Net (loss) income	$	(13,227)	$	219,730

We acquired Macpherson Energy because their assets are high-quality, low decline oil producing properties, and are a natural fit with our existing rural Kern County portfolio. In addition to the attractive base production, we see upside for near-term production enhancement and development opportunities.

Note 8—Earnings Per Share

We calculate basic earnings (loss) per share by dividing net income (loss) by the weighted-average number of common shares outstanding for each period presented. Common shares issuable upon the satisfaction of certain conditions pursuant to a contractual agreement, are considered common shares outstanding and are included in the computation of net income (loss) per share.

The RSUs and PSUs are not a participating security as the dividends are forfeitable. For the three and nine months ended September 30, 2023, no RSU or PSU shares were included in the diluted EPS calculation as their effect was anti-dilutive under the "if converted" method. For the three and nine months ended September 30, 2022, 4,001,000 and 4,168,000, RSU and PSU shares were included in the diluted EPS calculation, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(in thousands except per share amounts)			
Basic EPS calculation				
Net (loss) income	$ (45,062)	$ 191,660	$ (25,151)	$ 178,204
Weighted-average shares of common stock outstanding	75,662	78,044	76,163	79,304
Basic (loss) income per share	$ (0.60)	$ 2.46	$ (0.33)	$ 2.25
Diluted EPS calculation				
Net (loss) income	$ (45,062)	$ 191,660	$ (25,151)	$ 178,204
Weighted-average shares of common stock outstanding	75,662	78,044	76,163	79,304
Dilutive effect of potentially dilutive securities[1]	—	4,001	—	4,168
Weighted-average common shares outstanding - diluted	75,662	82,045	76,163	83,472
Diluted (loss) income per share	$ (0.60)	$ 2.34	$ (0.33)	$ 2.13

(1) We excluded approximately 1.9 million of combined RSUs and PSUs from the dilutive weighted-average common shares outstanding for each of the three and nine months ended September 30, 2023 because their effect was anti-dilutive.

Note 9—Revenue Recognition

We derive revenue from sales of oil, natural gas and natural gas liquids (“NGL”), with additional revenue generated from sales of electricity and marketing activities. Revenue from CJWS is generated from well servicing and abandonment business.

The following table provides disaggregated revenue for the three and nine months ended September 30, 2023 and 2022:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(in thousands)			
Oil sales	$ 168,491	$ 194,418	$ 475,138	$ 627,759
Natural gas sales	3,130	7,575	19,083	20,906
Natural gas liquids sales	990	1,592	2,450	5,342
Service revenue	45,511	48,594	137,808	134,608
Electricity sales	3,849	9,711	12,372	22,549
Marketing revenues	—	—	—	289
Other revenues	113	277	194	442
Revenues from contracts with customers	222,084	262,167	647,045	811,895
(Losses) gains on oil and gas sales derivatives	(103,282)	114,279	(43,912)	(88,237)
Total revenues and other	$ 118,802	$ 376,446	$ 603,133	$ 723,658

Note 10—Segment Information

We operate in two business segments: (i) E&P and (ii) well servicing and abandonment. The E&P segment is engaged in the exploration and production of onshore, low geologic risk, long-lived oil and gas reserves located in California and the Rockies. As of September 15, 2023, E&P also includes Macpherson Energy. The well servicing and abandonment segment is operated by CJWS and provides wellsite services in California to oil and natural gas production companies, with a focus on well servicing, well abandonment services and water logistics.

The well servicing and abandonment segment occasionally provides services to our E&P segment, as such, we recorded an intercompany elimination of $2 million and $5 million in revenue and expense during consolidation for the three and nine months ended September 30, 2023, respectively. The intercompany elimination was $1 million for the three and nine months ended September 30, 2022.

The following table represents selected financial information for the periods presented regarding the Company’s business segments on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis.

	Three Months Ended September 30, 2023			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues[1]	$ 176,573	$ 47,259	$ (1,748)	$ 222,084
Net (loss) income before income taxes	$ (35,485)	$ 3,295	$ (28,215)	$ (60,405)
Adjusted EBITDA	$ 79,491	$ 6,854	$ (16,516)	$ 69,829
Capital expenditures	$ 10,833	$ 2,104	$ 659	$ 13,596
Total assets	$ 1,604,253	$ 71,891	$ (62,219)	$ 1,613,925

	Three Months Ended September 30, 2022			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues[1]	$ 213,573	$ 49,427	$ (833)	$ 262,167
Net income (loss) before income taxes	$ 224,094	$ 5,168	$ (26,718)	$ 202,544
Adjusted EBITDA	$ 102,763	$ 7,726	$ (13,508)	$ 96,981
Capital expenditures	$ 38,312	$ 1,726	$ 779	$ 40,817
Total assets	$ 1,502,135	$ 79,696	$ (57,479)	$ 1,524,352

(1) These revenues do not include hedge settlements.

BERRY CORPORATION (bry)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

	Nine Months Ended September 30, 2023			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues[1]	$ 509,237	$ 142,921	$ (5,113)	$ 647,045
Net income (loss) before income taxes	$ 50,697	$ 10,245	$ (93,733)	$ (32,791)
Adjusted EBITDA	$ 233,562	$ 19,981	$ (55,322)	$ 198,221
Capital expenditures	$ 49,730	$ 4,420	$ 1,974	$ 56,124
Total assets	$ 1,604,253	$ 71,891	$ (62,219)	$ 1,613,925

	Nine Months Ended September 30, 2022			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues[1]	$ 677,287	$ 135,441	$ (833)	$ 811,895
Net income (loss) before income taxes	$ 258,689	$ 8,191	$ (78,998)	$ 187,882
Adjusted EBITDA	$ 325,354	$ 17,225	$ (40,139)	$ 302,440
Capital expenditures	$ 96,883	$ 3,420	$ 2,220	$ 102,523
Total assets	$ 1,502,135	$ 79,696	$ (57,479)	$ 1,524,352

(1) These revenues do not include hedge settlements.

BERRY CORPORATION (bry)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Adjusted EBITDA is the measure reported to the chief operating decision maker (CODM) for purposes of making decisions about allocating resources to and assessing performance of each segment. Adjusted EBITDA is calculated 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 unusual and infrequent items.

	Three Months Ended September 30, 2023			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation:				
Net (loss) income	$ (35,485)	$ 3,295	$ (12,872)	$ (45,062)
Add (Subtract):				
Interest (income) expense	—	(16)	9,117	9,101
Income tax benefit	—	—	(15,343)	(15,343)
Depreciation, depletion, and amortization	35,620	3,405	704	39,729
Losses on derivatives	94,857	—	—	94,857
Net cash paid for scheduled derivative settlements	(19,432)	—	—	(19,432)
Other operating expenses (income)	357	(6)	(856)	(505)
Stock compensation expense	108	176	2,734	3,018
Acquisition costs(1)	2,082	—	—	2,082
Non-recurring costs(2)	1,384	—	—	1,384
Adjusted EBITDA	$ 79,491	$ 6,854	$ (16,516)	$ 69,829

(1) Consists of costs related to the Macpherson Acquisition.

(2) Consists of costs related to the settlement of shareholder litigation.

	Three Months Ended September 30, 2022			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation:				
Net income (loss)	$ 224,094	$ 5,168	$ (37,602)	$ 191,660
Add (Subtract):				
Interest expense	—	4	7,863	7,867
Income tax expense	—	—	10,884	10,884
Depreciation, depletion, and amortization	35,198	3,249	1,059	39,506
Gains on derivatives	(143,221)	—	—	(143,221)
Net cash paid for scheduled derivative settlements	(14,739)	—	—	(14,739)
Other operating expenses (income)	1,077	(769)	315	623
Stock compensation expense	354	74	3,973	4,401
Adjusted EBITDA	$ 102,763	$ 7,726	$ (13,508)	$ 96,981

	Nine Months Ended September 30, 2023			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation:				
Net income (loss)	$ 50,697	$ 10,245	$ (86,093)	$ (25,151)
Add (Subtract):				
Interest (income) expense	—	(39)	25,771	25,732
Income tax benefit	—	—	(7,640)	(7,640)
Depreciation, depletion, and amortization	105,104	9,968	4,533	119,605
Losses on derivatives	48,901	—	—	48,901
Net cash received for scheduled derivative settlements	15,511	—	—	15,511
Other operating expenses (income)	1,073	(698)	(2,199)	(1,824)
Stock compensation expense	525	505	10,306	11,336
Acquisition costs[(1)]	3,054	—	—	3,054
Non-recurring costs[(2)]	8,697	—	—	8,697
Adjusted EBITDA	$ 233,562	$ 19,981	$ (55,322)	$ 198,221

(1) Consists of costs related to the Macpherson Acquisition.

(2) Non-recurring costs consists of the settlement of shareholder litigation in the third quarter of 2023 and executive transition costs and workforce reduction costs in the first quarter of 2023.

	Nine Months Ended September 30, 2022			
	E&P	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation:				
Net income (loss)	$ 258,689	$ 8,191	$ (88,676)	$ 178,204
Add (Subtract):				
Interest expense	—	4	23,267	23,271
Income tax expense	—	—	9,678	9,678
Depreciation, depletion, and amortization	104,628	9,445	3,265	117,338
Losses on derivatives	40,902	—	—	40,902
Net cash paid for scheduled derivative settlements	(84,519)	—	—	(84,519)
Other operating expenses (income)	4,601	(805)	949	4,745
Stock compensation expense	1,053	192	11,378	12,623
Non-recurring costs[(1)]	—	198	—	198
Adjusted EBITDA	$ 325,354	$ 17,225	$ (40,139)	$ 302,440

(1) Non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter of 2022.

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, 2022 (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, Berry Corporation (bry), a Delaware corporation (formerly known as Berry Petroleum Corporation,"Berry Corp."), together with its subsidiaries, Berry Petroleum, LLC, a Delaware limited liability company ("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"), (C&J Management and C&J together, "CJWS"). As of September 15, 2023, Berry LLC also owns Macpherson Energy, LLC (formerly, known as Macpherson Energy Corporation) and its subsidiaries ("Macpherson Energy").

Our Company

We are a value-driven western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived oil and gas reserves. We operate in two business segments: (i) exploration and production ("E&P") and (ii) well servicing and abandonment. Our E&P assets are located in California and the Rockies, characterized by high oil content and predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Rockies assets are in the Uinta basin of Utah (60% oil and 40% gas).

With respect to our E&P business in California, we focus on conventional, shallow oil reservoirs. The drilling and completion of such wells are relatively low-cost in contrast to unconventional resource plays. The California oil market is primarily tied to Brent-influenced pricing which has typically realized premium pricing relative to West Texas Intermediate ("WTI"). All of our California assets are located in oil-rich reservoirs in the San Joaquin basin, which has more than 150 years of production history and substantial oil remaining in place. As a result of the data generated over the basin's long history of production, its reservoir characteristics and low geological risk opportunities are generally well understood.

We also have upstream assets in the Rockies, located in the Uinta basin of Utah, which produce oil and natural gas at depths ranging from 4,000 feet to 7,000 feet. We have high operational control of our existing acreage (101,000 net acres), which provides significant upside for additional development and recompletions.

In our well servicing and abandonment segment, we operate one of the largest upstream well servicing and abandonment businesses in California, which operates as C&J. C&J provides wellsite services in California to oil and natural gas production companies, including well servicing and water logistics. Additionally, C&J performs plugging and abandonment services on wells at the end of their productive life, which we believe creates a strategic growth opportunity for Berry based on the significant market of idle wells within California.

The core of our strategy is to create value by generating significant free cash flow in excess of our operating costs, while optimizing capital efficiency. In doing so, we seek to maximize shareholder value through overall returns. Since our initial public offering in July 2018 ("IPO"), we have demonstrated our commitment to maximizing shareholder value and returning a substantial amount of capital to shareholders through dividends and share purchases. In early February 2023, we updated our shareholder return model, including the plan to double our quarterly fixed dividend to $0.12 per share. We also modified the allocations of Adjusted Free Cash Flow.

Our shareholder return model went into effect January 1, 2022, and we updated the allocations for 2023. Specifically, in 2023, the annual cumulative allocation of Adjusted Free Cash Flow is intended to be (a) 80% primarily in the form of debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets; and (b) 20% in the form of variable dividends. Any dividends (fixed or variable) actually paid will be determined by our Board of Directors in light of then existing conditions and circumstances, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors.

Like our business model, this shareholder return model is simple and demonstrates our commitment to optimize capital allocation and returns to our shareholders. As part of our strategy, we opportunistically consider bolt-on acquisitions, which contribute to our goal to maintain our existing production volumes (particularly in the current regulatory environment, when there are restrictions on the ability to obtain permits for new well drilling), and could even moderately grow production. Depending on size, bolt-on acquisitions may be funded in whole or in part from reallocation of maintenance capital or the 80% portion of our target Adjusted Free Cash Flow allocation, or a combination of both.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, bolt-on acquisitions or other growth opportunities, or other discretionary expenditures, since we have non-discretionary expenditures that are not deducted from this measure. Adjusted Free Cash Flow is a non-GAAP financial measure. See “Non-GAAP Financial Measures” for a reconciliation of cash provided by operating activities, our most directly comparable financial measure calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted Free Cash Flow.

We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling, sidetrack and workover locations with attractive full-cycle economics will support our objectives to generate free cash flow, which funds our operations, optimizes capital efficiency and maximizes shareholder returns. We also strive to maintain a strong liquidity position and low leverage profile that will enable us to explore attractive organic and strategic growth through commodity price cycles, both organically and through strategic acquisition opportunities. In addition to operating and developing our existing assets efficiently and strategically, we seek to acquire accretive, producing bolt-on properties that complement our existing operations, enhance our cash flows and allow us to further our strategy of keeping production essentially flat year-over-year. 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 safer, more efficient and lower emission operations.

As part of our commitment to creating long-term value for our shareholders, we are dedicated to conducting our operations in an ethical, safe and responsible manner, to protecting the environment, and to taking care of our people and the communities in which we live and operate. We believe that oil and gas will remain an important part of the energy landscape going forward and our goal is to conduct our business safely and responsibly, while supporting economic stability and social equity through engagement with our stakeholders. We recognize the oil and gas industry’s role in the energy transition and advocate a co-existence between renewable and conventional energy. We are committed to being part of the energy transition solution by continuing to provide safe, reliable, and affordable energy to our communities.

Recent Developments

In July 2023, we executed an agreement to acquire Macpherson Energy, a privately held Kern County, California operator and we closed the acquisition in September 2023 (“Macpherson Acquisition”). The total purchase price is approximately $70 million, subject to customary purchase price adjustments. The transaction was structured such that approximately $53 million has been paid at closing, including purchase price adjustments, and approximately $20 million will be paid in July 2024, subject to purchase price adjustments.

Consistent with our shareholder return model, Berry views this acquisition, in part, as a means of maintaining base production and expects to reallocate $30 to $35 million of planned 2023 capital expenditures to the purchase price, which will be deducted from maintenance capital in Adjusted Free Cash Flow for 2023. The remainder of the purchase price will be allocated from Adjusted Free Cash Flow consistent with our shareholder return model allocation. A portion of the closing price was initially funded by drawing down the 2021 RBL Credit Facility.

The Macpherson Energy assets are considered high-quality, low decline oil producing properties that are closely located to existing Berry properties in rural Kern County, California. These assets also align with Berry's stated strategy of acquiring accretive, producing bolt-ons. Macpherson Energy is reported under the E&P business segment.

How We Plan and Evaluate Operations

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) Adjusted Free Cash Flow for shareholder returns; (c) production from our E&P business (d) E&P field operations measures; (e) HSE results; (f) general and administrative expenses; and (g) the performance of our well servicing and abandonment operations based on activity levels, pricing and relative performance for each service provided.

Adjusted EBITDA

Adjusted EBITDA is the primary financial and operating measurement that our management uses to analyze and monitor the operating performance of both our E&P business and CJWS. We also use Adjusted EBITDA in planning our capital allocation to sustain production levels and determining our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility (defined below in "—Liquidity and Capital Resources"). 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 unusual and infrequent items. See "Management's Discussion and Analysis—Non-GAAP Financial Measures" for a reconciliation of net income (loss) and net cash provided (used) by operating activities, our most directly comparable financial measures calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted EBITDA. This supplemental non-GAAP financial measure is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

Shareholder Returns

Commencing in 2022, we implemented a shareholder return model based on our Adjusted Free Cash Flow, which is a non-GAAP measure that we define as cash flow from operations less regular fixed dividends and maintenance capital. Maintenance capital represents the capital expenditures needed to maintain substantially the same volume of annual oil and gas production and is defined as capital expenditures, excluding, when applicable, (i) E&P capital expenditures that are related to strategic business expansion, such as acquisitions and divestitures of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes, (ii) capital expenditures in our well servicing and abandonment segment, (iii) corporate expenditures that are related to ancillary sustainability initiatives and/or (iv) other expenditures that are discretionary and unrelated to maintenance of our core business. Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, bolt-on acquisitions or other growth opportunities, or other discretionary expenditures, since we have non-discretionary expenditures that are not deducted from this measure. Refer to "—Non-GAAP Financial Measures" for a reconciliation of the GAAP financial measure of operating cash flow, our most directly comparable financial measure calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted Free Cash Flow.

Under our shareholder return model, which was adjusted in February 2023, we plan to pay a fixed dividend of $0.12 per quarter. We also modified the allocations of Adjusted Free Cash Flow is intended to be (a) 80% primarily in the form of debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets; and (b) 20% in the form of variable dividends. Any dividends (fixed or variable) actually paid will be determined by our Board of Directors in light of then existing conditions and circumstances, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors.

Our focus on shareholder returns is also demonstrated through our performance-based restricted stock awards, which include performance metrics based on the Company's average cash returned on invested capital and total stockholder return on both a relative and absolute basis. Our short-term incentive plan also includes Adjusted Free Cash Flow performance goals.

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.

E&P Field Operations

Overall, management assesses the efficiency of our E&P field operations by considering core E&P operating expenses together with our cogeneration, marketing and transportation activities. In particular, a core component of our E&P operations in California is steam, which we use to lift heavy oil to the surface. We operate several cogeneration facilities to produce some of the steam needed in our operations. In comparing the cost effectiveness of our cogeneration plants against other sources of steam in our operations, management considers the cost of operating the cogeneration plants, including the cost of the natural gas purchased to operate the facilities, against the value of the steam and electricity used in our E&P field operations and the revenues we receive from sales of excess electricity to the grid. We strive to minimize the variability of our fuel gas costs for our California steam operations with natural gas purchase hedges. Consequently, the efficiency of our E&P field operations are impacted by the cash settlements we receive or pay from these derivatives. We also have contracts for the transportation of fuel gas from the Rockies which has historically been cheaper than the California markets. With respect to transportation and marketing, management also considers opportunistic sales of incremental capacity in assessing the overall efficiencies of E&P operations.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Electricity generation expenses include the portion of fuel, labor, maintenance, and tools and supplies from two of our cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to our costs to transport the oil and gas that we produce within our properties or move it to the market. Marketing 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. Electricity revenue is from the sale of excess electricity from two of our cogeneration facilities to a California utility company under long-term contracts at market prices. These cogeneration facilities are sized to satisfy the steam needs in their respective fields, but the corresponding electricity produced is more than the electricity that is currently required for the operations in those fields. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

Health, Safety & Environmental

Like other companies in the oil and gas industry, the operations of both our E&P business and CJWS are subject to complex federal, state and local laws and regulations that govern health and safety, the release or discharge of materials, and land use or environmental protection that may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Please see “—Regulatory Matters” in this quarterly report as well as Part I, Item 1 “Regulatory Matters” and Part I, Item 1A. “Risk Factors” in our Annual Report for a discussion of the potential impact that government regulations, including those regarding HSE matters, may have upon our business, operations, capital expenditures, earnings and competitive position.

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

Well Servicing and Abandonment Operations Performance

We consistently monitor our well servicing and abandonment operations performance with revenue and cost by service and customer, as well as Adjusted EBITDA for this business.

Business Environment, Market Conditions and Outlook

Our operating and financial results, and those of the oil and gas industry as a whole, are heavily influenced by commodity prices, including differentials, which have and may continue to, fluctuate significantly as a result of numerous market-related variables, including global geopolitical and economic conditions, and local and regional market factors and dislocations. Oil prices have decreased in 2023 compared to 2022, but have shown an upward trend in the third quarter of 2023. Oil prices have remained, and may continue to remain, volatile.

Our well services and abandonment business is dependent on expenditures of oil and gas companies, which can in part reflect the volatility of commodity prices. Because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by oil and gas companies for the maintenance of existing wells historically have been relatively stable and predictable when production is steady. Additionally, our customers' requirements to plug and abandon wells are largely driven by regulatory requirements that are less dependent on commodity prices.

Currently, global oil inventories supplied from OPEC+ and other oil producing nations are expected to transition from inventory builds during the first half of 2023 to inventory decreases throughout the majority of 2024. Since October 2022, OPEC+ announced reductions in production that extend through December 2023. In June 2023, OPEC+ further reduced required production beginning in January 2024 through December 2024, compared to the October 2022 announcement. In September 2023, Saudi Arabia and Russia announced they were continuing their sustained production cuts until the end of the year.

Furthermore, sanctions and import bans on Russian oil have been implemented by various countries in response to the ongoing conflict in Ukraine, further impacting global oil supply. While oil prices declined in the first half of 2023 from their 2022 highs, oil prices rebounded in the third quarter of 2023 due to stronger than anticipated economic growth and sustained production cuts from Saudi Arabia and Russia. Natural gas prices have stabilized since Q2 2023. Oil and natural gas prices could decrease or increase with any changes in demand due to, among other things, the ongoing conflict in Ukraine, the recent Israel-Hamas conflict, international sanctions, speculation as to future actions by OPEC+, higher gas prices, rising interest rates, inflation and government efforts to reduce inflation, and possible changes in the overall health of the global economy, including increased volatility in financial and credit markets or a prolonged recession. Further, the volatility in oil and natural gas prices could accelerate a transition away from fossil fuels, resulting in reduced demand over the longer term. To what extent these and other external factors (such as government action with respect to climate change regulation) ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors, including future developments, that are not within our control and cannot be accurately predicted.

Commodity Pricing and Differentials

Our revenue, costs, profitability, shareholder returns 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 I, Item 1A. "Risk Factors" in our Annual Report. We utilize derivatives 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.

Average Brent oil prices, as noted below, increased by $8.19, or 11%, for the three months ended September 30, 2023 compared to the three months ended June 30, 2023 and decreased by $11.78, or 12%, compared to the three months ended September 30, 2022. Though the California market generally receives Brent-influenced pricing, California oil prices are determined by local supply and demand dynamics, including third-party transportation and infrastructure capacity. The year-over-year decrease in average Brent oil prices is primarily related to the significant increase in oil and gas prices during the second quarter of 2022 caused by the Ukraine conflict. In 2023, Brent oil prices decreased from the high prices observed in 2022. In the third quarter of 2023, prices increased but remained lower than the elevated levels of 2022.

For our California steam operations, the price we pay for fuel gas purchases is generally based on the Northwest, Rocky Mountains index for the purchases made in the Rockies and the SoCal Gas city-gate index for the purchases made in California. We currently buy most of our gas in the Rockies. Now that we are purchasing a majority of our fuel gas in the Rockies, most of the purchases made in California use the SoCal Gas city-gate index, whereas prior to this shift the predominant index for California purchases was Kern, Delivered. The price from the Northwest, Rocky Mountain index was as high as $3.98 per mmbtu and as low as $2.95 per mmbtu in the third quarter of 2023. The price from the SoCal Gas city-gate index was as high as $9.60 per mmbtu and as low as $5.56 per mmbtu in the third quarter of 2023. Overall, we paid an average of $4.18 per mmbtu in the third quarter of 2023, excluding the impact of our gas purchase hedges. The price we paid on average increased by $0.74 per mmbtu, or 22% and decreased $3.98 per mmbtu, or 49% for the third quarter of 2023, compared to the second quarter of 2023 and the third quarter of 2022, respectively. When including hedging effects in our gas purchases, we paid $5.61, $5.64 and $5.63 per mmbtu in the third quarter of 2023, the second quarter of 2023, and the third quarter of 2022, respectively.

The following table presents the average Brent, WTI, SoCal Gas city-gate, Northwest, Rocky Mountains, and Henry Hub prices for the three months ended September 30, 2023, June 30, 2023 and September 30, 2022 and for the nine months ended September 30, 2023 and September 30, 2022:

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
Oil (bbl) – Brent	$ 85.92	$ 77.73	$ 97.70	$ 81.96	$ 102.48
Oil (bbl) – WTI	$ 81.99	$ 73.73	$ 91.96	$ 77.31	$ 98.39
Natural gas (mmbtu) – SoCal Gas city-gate	$ 7.10	$ 5.66	$ 9.55	$ 12.52	$ 7.94
Natural gas (mmbtu) – Northwest, Rocky Mountains	$ 3.40	$ 2.85	$ 7.79	$ 9.54	$ 6.75
Natural gas (mmbtu) – Henry Hub	$ 2.59	$ 2.16	$ 8.03	$ 2.46	$ 6.74

California oil prices are Brent-influenced as California refiners import approximately 75% 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 wells and recompletions.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. Our key exposure to gas prices is in our costs. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities than we produce and sell in the Rockies. In May 2022, we began purchasing most of our gas in the Rockies and transporting it to our California operations using our Kern River pipeline capacity. We buy approximately 48,000 mmbtu/d in the Rockies, and the remainder comes from California markets. The volume purchased in California fluctuates and averaged 6,000 mmbtu/d in Q3 2023, 6,000 mmbtu/d in Q2 2023 and 10,000 mmbtu/d in Q3 2022. The natural gas we purchase in the Rockies is shipped to our operations in California to help limit our exposure to California fuel gas purchase price fluctuations. We strive to further minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of our gas purchases. 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. The Kern capacity allows us to purchase and sell natural gas at the same pricing indices.

Among other factors, cold weather conditions drove high natural gas prices in 2022. In California we experienced some increase in the third quarter of 2022 and a significant increase in mid-December 2022, with gas prices briefly as high as $50.79 per mmbtu. We quickly pivoted and reduced our gas consumption in California by temporarily shutting-down one of our cogeneration facilities and reducing steam generation in other parts of our operation, which negatively impacted production. We seek to mitigate a substantial portion of the gas purchase exposure for our cogeneration plants by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. Aside from the impact gas prices have on electricity prices, these sales are generally higher in the summer months as they include seasonal capacity amounts. Our current expectations are that natural gas prices in the western US will continue to remain elevated in 2023 relative to Henry Hub. Our hedging strategy coupled with our midstream access to gas from the Rockies helps us mitigate the impact of high natural gas prices on our cost structure.

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 two of our cogeneration facilities under contracts with terms ending in December 2023, December 2024 (with this term beginning January 2024), and November 2026. The most significant input and cost of the cogeneration facilities is natural gas.

Additionally, like other companies in the oil and gas industry, our operations are subject to stringent federal, state and local laws and regulations relating to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing, and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. For more information related to regulatory risks, see "Item 1A. Risk Factors—Risks Related to Our Operations and Industry" in our Annual Report.

Regulatory Matters

Like other companies in the oil and gas industry, both our E&P business and CJWS are subject to complex and stringent federal, state, and local laws and regulations, and California, where most of our operations and assets are located, is one of the most heavily regulated states in the United States with respect to oil and gas operations. A combination of federal, state and local laws and regulations govern most aspects of our activities in California, and federal, state and local agencies assert overlapping authority to regulate in some areas. Collectively, the effect of the existing laws and regulations is to limit the number and location of our wells through restrictions on the use of our properties; limit our ability to develop certain assets and conduct certain operations, including through a restrictive and burdensome permitting and approval process; and regulate the amount of oil and natural gas that we can produce from our wells, potentially reducing below levels that would otherwise be possible. Additionally, changes in the legal and regulatory requirements in the past has, and in the future could, result in increased costs, which may have an adverse effect upon operations, capital expenditures, earnings and our competitive position. Violations and liabilities with respect to these laws and regulations could also result in significant administrative, civil, or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns, and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and future prospects. Our operations in California are particularly exposed to increased regulatory risks given the stringent environmental regulations imposed on the oil and gas industry. Additionally, current political and social trends in California have, and in the future could, result in increased limitations and additional permitting, mitigation, and emission control obligations, amongst others, upon the oil and gas industry. We cannot predict what new health, safety and environmental laws or regulations California may impose upon our operations in the future; however, any such future laws or regulations could materially and adversely impact our business and results of operations. For additional information about the potential impact that government regulations, including those regarding environmental matters, may have upon our business, operations, capital expenditures, earnings and competitive position, please see Part I, Item 1 “Regulatory Matters,” as well as Part I, Item 1A. “Risk Factors” in our Annual Report.

Over the last few years, a number of developments at both the California state and local levels have resulted in significant delays in the issuance of permits to drill new oil and gas wells in Kern County, where all of our California assets are located. The issuance of permits and other approvals for drilling and production activities by state and local agencies or by federal agencies are subject to environmental reviews under the California Environmental Quality Act (“CEQA”) and/or the National Environmental Policy Act (“NEPA”), respectively. This requirement to demonstrate compliance with CEQA and/or NEPA is resulting currently (and in the future may result) in delays in the issuance of necessary permits and approvals and the imposition of mitigation measures or restrictions on proposed oil field operations, among other things. Before an operator can pursue drilling operations in California, they must first obtain permission to engage in oil and gas land use. CEQA requires that the reviewing state and local agencies consider the environmental impacts of the proposed oil and gas operations for permitting decisions. Historically, we satisfied CEQA by complying with the Kern County zoning ordinance for oil and gas operations, which was supported by the Kern County Environmental Impact Report (“EIR”). However, the EIR was legally challenged in 2020 and the litigation proceedings are ongoing; as a result, use of the EIR is currently stayed and has been stayed through most of the litigation. Accordingly, our ability to rely on the EIR to demonstrate CEQA compliance to obtain permits and approvals is constrained until Kern County is able to favorably resolve the litigation. As a result of the litigation, to date in 2023 neither we nor any other operator have received permits to drill new wells where the EIR is needed to demonstrate CEQA compliance. In the meantime, to obtain permits for drilling new wells in Kern County we must demonstrate compliance with CEQA to CalGEM through means other than the EIR. Berry does have a separate environmental impact analysis covering certain assets, and we have historically received permits to drill new wells in the covered areas. However, we began to experience delays in the issuance of new drill permits in those areas during the third quarter of 2023, which we believe is due to changes in CalGEM’s CEQA review process. In fact, since January 2023, relatively few permits to drill new wells in California have been issued to any oil producer. Additionally, in the third quarter of 2023, we started to experience delays in the approval process for workover and sidetrack permits as well, which we believe is also due to changes in CalGEM’s review process. Although we are still developing our 2024 plans and so our current views are dynamic, we currently have sufficient permits in hand that should allow us to maintain drilling activity through around May

2024 and a continuous workover campaign for approximately the first half of the year. The permitting applications necessary to hold production flat for the full year 2024 have been submitted to CalGEM and are pending approval. With respect to the new drill permits pending CalGEM review, 14 are for wells in areas for which we have a separate environmental impact analysis and 79 are in areas where the EIR is needed to demonstrate CEQA compliance. With respect to the latter, those 79 permit applications have already received local approval via the issuance of a Kern County permit, and to help ensure efficient processing and final approval of those permits by CalGEM once the EIR is reinstated, we are seeking conditional approval of those permits from CalGEM, subject to reinstatement of the EIR to confirm CEQA compliance. See Part I, Item 1 and 2. “Business and Properties—Regulatory Matters” in our Annual Report and Part I, Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters” in our Quarterly Reports on Form 10-Q for the three months ended March 31, 2023 and June 30, 2023, as well as Part I, Item 1A. “Risk Factors” in our Annual Report for more information regarding the EIR and other permitting considerations.

On September 16, 2022, the California Governor signed into law Senate Bill No. 1137 (SB 1137) which prohibits CalGEM from permitting any new wells, or the rework of existing wells, if the proposed new drill or rework is within 3,200 feet of certain sensitive receptors such as homes, schools or parks. The bill would have become effective January 1, 2023. However, in December 2022, proponents of a voter referendum (the “Referendum”) collected more than the required number of signatures to put Senate Bill No. 1137 on the November 2024 ballot. On February 3, 2023, the Secretary of State of California certified the signatures and confirmed that the Referendum qualifies for the November 2024 ballot. Accordingly, Senate Bill No. 1137 is stayed until it is put to a vote. Relatedly, a legislator introduced Senate Bill No. 556 (SB 556) into the California Senate providing for joint and several liability for operators and owners of an entity that owns an oil and gas production facility for certain adverse health conditions within 3,200 feet of such facility, subject to limited defenses. Senate Bill No. 556 also provides for civil penalties to be assessed against potentially responsible parties. Senate Bill No. 556 has been held in a legislative committee and, pursuant to legislative rules, cannot be further considered until 2024. We continue to assess the impacts of Senate Bill No. 1137 and the potential impacts of Senate Bill No. 556, including on our ability to operate and any increased exposure to liability.

Assembly Bill 1167 (AB 1167), signed into law by the California Governor in October 2023, imposes more stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in the state of California. AB 1167 requires such persons to fulfill bonding requirements in an amount determined by the state to sufficiently cover full plugging and abandonment costs, decommissioning, and site restoration of all wells and production facilities. Transfer of operatorship of a well or production facility is prohibited until the state has determined the appropriate bond amount and the bond has been filed. Upon signing AB 1167, the California Governor called for further legislative changes to the new requirements to mitigate against the potential risk of an increase in the number of orphaned wells becoming state liabilities following the implementation of the law.

In October 2023, the California Governor signed two bills that require quantitative and qualitative climate disclosures for certain public and private companies doing business in California. Senate Bill 253 (SB 253) requires the annual disclosure of Scope 1, 2 and 3 GHG emissions, with certain emissions data subject to third party assurance. The bill requires disclosure of Scope 1 and 2 GHG emissions beginning in 2026 for the 2025 reporting year and disclosure of Scope 3 GHG emissions beginning in 2027 for the 2026 reporting year. SB 253 is effective for public and private companies with total annual revenues exceeding $1 billion. Senate Bill 261 (SB 261) requires biennial disclosures posted on a company’s website related to climate-related financial risks and the measures a company has adopted to reduce and adapt to such risks. The bill requires disclosure of the climate-related financial risk disclosures beginning in 2026 for the 2025 reporting year. SB 261 is effective for public and private companies with total annual revenues exceeding $500 million.

Inflation

The U.S. inflation rate increased throughout much of 2022. The Company, similar to other companies in our industry, has experienced inflationary pressures on our costs—namely inflationary pressures have resulted in increases to the costs of our goods, services and personnel, which in turn, have caused our capital expenditures and operating costs to rise. Such inflationary pressures have resulted from supply chain disruptions caused by the COVID-19 pandemic, increased demand, labor shortages and other factors, including the conflict between Russia and Ukraine, which began in late February 2022. In late 2022 and through 2023, inflation rates began to stabilize and even decrease from the levels experienced earlier in 2022. We are unable to accurately predict if such inflationary pressures and contributing factors will continue through the remainder of 2023. However, as of September 30, 2023, we determined there have not been any material changes in inflationary pressures since the year ended December 31, 2022.

Seasonality

Seasonal weather conditions have in the past, and in the future likely will, impact our drilling, production and well servicing activities. Extreme weather conditions can pose challenges to meeting well-drilling and completion objectives and production goals. Seasonal weather can also lead to increased competition for equipment, supplies and personnel, which could lead to shortages and increased costs or delayed operations. Our operations have been, and in the future could 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 wildfires and rain. For example, during the first quarter of 2023, we experienced an increase in costs, production downtime and transportation delays due to the unprecedented snowy and rainy weather in Utah and California. Unusually heavy rains caused flooding and power outages which adversely impacted our ability to operate in California, while Utah was impacted by historic snowfall. Beginning April 2023, the weather improved and our production recovered in the second and third quarters of 2023.

Many factors influence the price of natural gas including the weather. For example, natural gas prices decreased in the second and third quarters of 2023 in part because extreme cold and winter storms from the first quarter of 2023 moderated. We seek to mitigate a substantial portion of the gas purchase exposure for our cogeneration plants by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. Aside from the impact gas prices have on electricity prices, these sales are generally higher in the summer months as they include seasonal capacity amounts. Our hedging strategy coupled with our midstream access to gas from the Rockies also helps mitigate the impact of the high natural gas prices on our cost structure.

Capital Expenditures

For the three and nine months ended September 30, 2023, our total capital expenditures were approximately $14 million and $56 million, respectively, including capitalized overhead and interest and excluding acquisitions and asset retirement spending. E&P and corporate expenditures were $12 million and $52 million for the three and nine months ended September 30, 2023, respectively (excluding well servicing and abandonment capital of $2 million and $4 million for the three and nine months ended September 30, 2023, respectively). Approximately 90% and 10% of these capital expenditures for the nine months ended September 30, 2023 were directed to California and Utah operations, respectively.

Our initial 2023 capital expenditure budget for E&P operations and corporate activities was between $95 to $105 million, which we expected would result in a slight decline in production year-over-year. This capital expenditure budget excludes approximately $8 million for CJWS. In connection with the closing of the Macpherson Acquisition in September 2023, we expect to reallocate approximately $30 to $35 million of our initial capital expenditure budget to fund a portion of the purchase price of the Macpherson Acquisition. The decreased E&P and corporate capital budget of $68 million to $74 million includes a reduction in drilling, workover and other activities on the legacy Berry assets, accordingly. Based on current commodity prices and our drilling success to date, we expect to be able to fund the remainder of our 2023 capital development programs from cash flow from operations.

Our capital program for 2023 focuses on new wells for which we already had permits or existing CEQA analysis completed at the beginning of 2023, and otherwise focuses on workovers and other activities related to existing wellbores. As a result of ongoing regulatory uncertainty in California impacting the permitting process in Kern County where all of our California assets are located, the capital program was prepared based on certain permitting assumptions. We assumed that we would continue to timely receive new well drilling permits in CEQA covered areas. We further assumed that we would obtain the other permits and approvals needed for planned workover and sidetrack activities. We are also pursuing alternative avenues to obtain additional permits for new wells that, if received could enable us to expand the 2023 drilling program contemplated under our capital budget. However, we have not received additional permits for new well drilling, including in CEQA covered areas, to date in 2023. Nevertheless, we expect to be able to meet 2023 production targets without the need for additional permits for new well drilling. Please see “—Regulatory Matters” in this Quarterly Report, as well as in our Annual Report, for additional discussion of the laws and regulations that impact our ability to drill and develop our assets, including those impacting regulatory approval and permitting requirements.

Exclusive of the capital expenditures noted above, for the full year 2023, we plan to spend approximately $21 million to $24 million on plugging and abandonment activities, exceeding our annual obligation requirements under California idle well program. We spent approximately $4 million and $15 million for plugging and abandonment activities in the three and nine months ended September 30, 2023, respectively.

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, 2023	June 30, 2023	September 30, 2022
Average daily production:[1]			
Oil (mbbl/d)	23.2	24.0	23.7
Natural Gas (mmcf/d)	9.5	9.2	10.4
NGL (mbbl/d)	0.5	0.4	0.4
Total (mboe/d)[2]	25.3	25.9	25.8
Total Production:			
Oil (mbbl)	2,136	2,186	2,171
Natural gas (mmcf)	877	839	953
NGLs (mbbl)	44	35	39
Total (mboe)[2]	2,326	2,361	2,369
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 78.89	$ 70.68	$ 89.54
Effects of scheduled derivative settlements ($/bbl)	$ (5.76)	$ (0.81)	$ (13.13)
Oil with hedges ($/bbl)	$ 73.13	$ 69.87	$ 76.41
Natural gas ($/mcf)	$ 3.57	$ 2.87	$ 7.95
NGL ($/bbl)	$ 22.54	$ 22.16	$ 40.72
Average Benchmark prices:			
Oil (bbl) – Brent	$ 85.92	$ 77.73	$ 97.70
Oil (bbl) – WTI	$ 81.99	$ 73.73	$ 91.96
Natural gas (mmbtu) – SoCal Gas city-gate[3]	$ 7.10	$ 5.66	$ 9.55
Natural gas (mmbtu) – Northwest, Rocky Mountains[4]	$ 3.40	$ 2.85	$ 7.79
Natural gas (mmbtu) – Henry Hub[4]	$ 2.59	$ 2.16	$ 8.03

(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, 2023, the average prices of Brent oil and Henry Hub natural gas were $85.92 per bbl and $2.59 per mmbtu.

(3) The natural gas we purchase to generate steam and electricity is primarily based on Rockies price indexes, including transportation charges, as we currently purchase a substantial majority of our gas needs from the Rockies, with the balance purchased in California. SoCal Gas city-gate Index is the relevant index used only for the portion of gas purchases in California. Now that we are purchasing a majority of our fuel gas in the Rockies, most of the purchases made in California utilize the SoCal Gas city-gate index, whereas prior to this shift the predominant index for California purchases were Kern, Delivered.

(4) Northwest, Rocky Mountains and Henry Hub are the relevant indices used for gas purchases and sales, respectively, in the Rockies.

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

	Three Months Ended		
	September 30, 2023	June 30, 2023	September 30, 2022
Average daily production (mboe/d):[(1)]			
California	20.5	20.8	20.8
Utah	4.8	5.1	5.0
Total average daily production	25.3	25.9	25.8

(1) Production represents volumes sold during the period.

Our average daily production increased 1%, or 0.2 mboe/d, when compared to the first half of 2023. On a sequential basis our average daily production decreased 2%, or 0.6 mboe/d, for the three months ended September 30, 2023, compared to the three months ended June 30, 2023. Our California production was 20.5 mboe/d for the third quarter of 2023, a decrease of 0.3 mboe/d from the second quarter of 2023, which was principally due to lower drilling and workover activities (see "—Capital Expenditures" for further discussion) and accumulated inventory from first quarter production sold in the second quarter due to weather issues. The Utah decline was due to higher shipments in the second quarter of 2023 from oil inventory stacked in the first quarter of 2023 during severe winter storms.

Average daily production in both California and Utah for the three months ended September 30, 2023 decreased 2%, or 0.5 mboe/d, compared to the three months ended September 30, 2022. The lower production was due to our reduced capital drilling program in 2023. For instance, we drilled three wells in the third quarter of 2023 and 14 in the same period of 2022.

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, 2023	September 30, 2022
Average daily production:[(1)]		
Oil (mbbl/d)	23.3	24.0
Natural Gas (mmcf/d)	9.1	11.0
NGL (mbbl/d)	0.4	0.4
Total (mboe/d)[(2)]	25.2	26.2
Total Production:		
Oil (mbbl)	6,359	6,551
Natural gas (mmcf)	2,495	2,990
NGLs (mbbl)	99	111
Total (mboe)[(2)]	6,874	7,160
Weighted-average realized sales prices:		
Oil without hedges ($/bbl)	$ 74.72	$ 95.83
Effects of scheduled derivative settlements ($/bbl)	$ (3.38)	$ (16.81)
Oil with hedges ($/bbl)	$ 71.34	$ 79.02
Natural gas ($/mcf)	$ 7.65	$ 6.99
NGL ($/bbl)	$ 24.73	$ 47.98
Average Benchmark prices:		
Oil (bbl) – Brent	$ 81.96	$ 102.48
Oil (bbl) – WTI	$ 77.31	$ 98.39
Natural gas (mmbtu) – SoCal Gas city-gate[(3)]	$ 12.52	$ 7.94
Natural gas (mmbtu) – Northwest, Rocky Mountains[(4)]	$ 9.54	$ 6.75
Natural gas (mmbtu) – Henry Hub[(4)]	$ 2.46	$ 6.74

(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, 2023, the average prices of Brent oil and Henry Hub natural gas were $81.96 per bbl and $2.46 per mmbtu respectively.

(3) The natural gas we purchase to generate steam and electricity is primarily based on Rockies price indexes, including transportation charges, as we currently purchase a substantial majority of our gas needs from the Rockies, with the balance purchased in California. SoCal Gas city-gate Index is the relevant index used only for the portion of gas purchases in California. Now that we are purchasing a majority of our fuel gas in the Rockies, most of the purchases made in California utilize the SoCal Gas city-gate index, whereas prior to this shift the predominant index for California purchases were Kern, Delivered.

(4) Northwest, Rocky Mountains and Henry Hub are the relevant indices used for gas purchases and sales, respectively, in the Rockies.

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

	Nine Months Ended	
	September 30, 2023	September 30, 2022
Average daily production (mboe/d):[(1)]		
California	20.4	21.3
Utah[(2)]	4.8	4.8
Colorado[(3)]	—	0.1
Total average daily production	25.2	26.2

(1) Production represents volumes sold during the period.

(2) Includes production for Antelope Creek area from February 2022, when it was acquired, through September 30, 2023.

(3) In January 2022, we divested all of our natural gas properties in Colorado.

Average daily production for the nine months ended September 30, 2023 decreased by 1.0 mboe/d, or 4%, compared to the same period in 2022. California produced 20.4 mboe/d for the nine months ended September 30, 2023, a decrease of 0.9 mboe/d, or 4%, when compared to the nine months ended September 30, 2022 due to weather-related downtime in the first quarter of 2023 and less development activity in the nine months ended September 30, 2023 compared to the same period of 2022. We drilled 29 wells in California in the first nine months of 2023, of which 26 were producing wells and three were injector wells compared to 63 total wells drilled in the first nine months of 2022. Average daily production remained flat in Utah. We divested our Colorado asset in the first quarter of 2022, which accounted for 0.1 mboe/d of production in the first nine months of 2022.

Results of Operations

Three Months Ended September 30, 2023 compared to Three Months Ended June 30, 2023.

	Three Months Ended			
	September 30, 2023	June 30, 2023	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 172,611	$ 157,703	$ 14,908	9 %
Service revenue	45,511	47,674	(2,163)	(5)%
Electricity sales	3,849	3,078	771	25 %
(Losses) gains on oil and gas sales derivatives	(103,282)	20,871	(124,153)	(595)%
Marketing and other revenues	113	36	77	214 %
Total revenues and other	$ 118,802	$ 229,362	$ (110,560)	(48)%

Revenues and Other

Oil, natural gas and NGL sales increased by $15 million, or 9%, to approximately $173 million for the three months ended September 30, 2023, compared to the three months ended June 30, 2023. The increase was driven by an $18 million increase in oil prices and a $1 million increase in gas prices, partially offset by a $4 million decrease in oil volumes.

Service revenue consisted entirely of revenue from the well servicing and abandonment business. Service revenue decreased by $2 million, or 5%, to approximately $46 million for the three months ended September 30, 2023, compared to the three months ended June 30, 2023. The decrease was driven by a change in service mix in the third quarter compared to the second quarter. The well servicing and abandonment segment periodically provides services to our E&P segment, as such, we recorded an intercompany elimination of approximately $2 million in revenue and expense in each of the quarters presented. Service revenues in the table above are presented net of intercompany amounts.

Electricity sales represent sales to utilities and increased $1 million, or 25%, to approximately $4 million for the three months ended September 30, 2023 compared to the three months ended June 30, 2023. This increase was due to a 29% increase in prices in the third quarter of 2023, partially offset by a 3% decrease in volumes when compared to the second quarter of 2023.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement losses for the three months ended September 30, 2023 and June 30, 2023 were $12 million and $2 million, respectively. This quarter-over-quarter increased loss was primarily due to higher Brent index prices, the index for all our oil derivatives. The mark-to-market non-cash loss for the three months ended September 30, 2023 was $91 million compared to a gain of $23 million in the three months ended June 30, 2023. Because we are the floating price payer on these swaps, generally, period to period decreases (increases) in the associated price index create valuation gains (losses).

Marketing and other revenues, which included third-party marketing activities, were not material for the three months ended September 30, 2023 and June 30, 2023.

	Three Months Ended			
	September 30, 2023	June 30, 2023	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 59,842	$ 54,707	$ 5,135	9 %
Costs of services	35,806	37,083	(1,277)	(3)%
Electricity generation expenses	1,479	1,273	206	16 %
Transportation expenses	1,089	1,096	(7)	(1)%
Acquisition costs(1)	2,082	972	1,110	114 %
General and administrative expenses	20,987	22,488	(1,501)	(7)%
Depreciation, depletion and amortization	39,729	39,755	(26)	— %
Taxes, other than income taxes	17,980	13,707	4,273	31 %
(Gains) losses on natural gas purchase derivatives	(8,425)	14,024	(22,449)	n/a
Other operating income	(505)	(1,033)	(528)	(51)%
Total expenses and other	170,064	184,072	(14,008)	(8)%
Other (expenses) income:				
Interest expense	(9,101)	(8,794)	(307)	3 %
Other, net	(42)	(110)	68	(62)%
Total other expenses	(9,143)	(8,904)	(239)	3 %
(Loss) income before income taxes	(60,405)	36,386	(96,791)	(266)%
Income tax (benefit) expense	(15,343)	10,616	(25,959)	245 %
Net (loss) income	$ (45,062)	$ 25,770	$ (70,832)	(275)%
Adjusted EBITDA(2)	$ 69,829	$ 69,055	$ 774	1 %
Adjusted Net Income(2)	$ 11,831	$ 11,666	$ 165	1 %

(1) Consists of costs related to the Macpherson Acquisition.

(2) Adjusted EBITDA and Adjusted Net Income (Loss) are financial measures that are not calculated in accordance with GAAP. For definitions and a reconciliation to the Net Cash Provided by Operating Activities and Net Income (loss), please see “—Non-GAAP Financial Measures”.

Expenses

Lease operating expenses, which do not include the effects of gas purchase hedges, increased 9% or $5 million to $60 million for the third quarter of 2023 when compared to the second quarter of 2023. The majority of this increase was the result of higher natural gas (fuel) costs of $4 million for our California steam generation facilities due to an increase in fuel prices. Lease operating expenses excluding fuel increased $1 million due to higher power costs as we incurred the higher seasonal summer rates in the third quarter of 2023.

Cost of services decreased $1 million, or 3%, to $36 million in the third quarter of 2023 due to a change in mix and volume of services.

Electricity generation expenses was relatively flat for the three months ended September 30, 2023 compared to the three months ended June 30, 2023.

Transportation expenses were comparable for the periods presented.

Gains and losses on natural gas purchase derivatives resulted in a gain of $8 million for the three months ended September 30, 2023 and a loss of $14 million for the three months ended June 30, 2023. Settlements for the three months ended September 30, 2023 and June 30, 2023 were a loss of $7 million, or $3.06 per boe, and a loss of $11 million, or $4.55 per boe, respectively. The decreased loss was due to an increase in settlement price in the third quarter of 2023 compared to the second quarter while fixed price remained the same. The mark-to-market valuation gain for the three months ended September 30, 2023 was $16 million compared to a loss of $3 million for the three months ended June 30, 2023. Because we are the fixed price payer on these natural gas swaps, generally, period to period increases (decreases) in the associated price index create valuation gains (losses).

Acquisition costs increased $1 million for the three months ended September 30, 2023 compared to the three months ended June 30, 2023, primarily due to legal and other professional expenses associated with the Macpherson Acquisition.

General and administrative expenses decreased almost $2 million, or 7%, to $21 million for the three months ended September 30, 2023, compared to the three months ended June 30, 2023 primarily due to lower expenses related to the shareholder litigation. For each of the three months ended September 30, 2023 and June 30, 2023, general and administrative expenses included non-cash stock compensation costs of approximately $3 million. We incurred non-recurring costs of approximately $1 million for the three months ended September 30, 2023 and none for the three months ended June 30, 2023.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased $2 million, or 12% for the three months ended September 30, 2023 compared to the three months ended June 30, 2023. The decrease was largely a result of lower shareholder litigation expenses. See “—Non-GAAP Financial Measures” for a reconciliation of general and administrative expense, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General and Administrative Expenses.

DD&A was flat for the three months ended September 30, 2023 compared to the three months ended June 30, 2023.

Taxes, Other Than Income Taxes

	Three Months Ended			
	September 30, 2023	June 30, 2023	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.47	$ 1.44	$ 0.03	2 %
Ad valorem and property taxes	2.12	1.87	0.25	13 %
Greenhouse gas allowances	4.14	2.50	1.64	66 %
Total taxes other than income taxes	$ 7.73	$ 5.81	$ 1.92	33 %

Taxes, other than income taxes, increased in the three months ended September 30, 2023 by $1.92 per boe, or 33%, to $7.73. The increase in the greenhouse gas (“GHG”) allowance expense was a result of higher non-cash mark-to-market prices for the allowances in the third quarter of 2023 compared to the second quarter of 2023.

Interest Expense

Interest expense was flat for the three months ended September 30, 2023, compared to the three months ended June 30, 2023.

Income Taxes

Our effective tax rate was 25% for the three months ended September 30, 2023 and 29% for the three months ended June 30, 2023. The rate in the third quarter of 2023 was due to the tax effect of the book loss in the third quarter of 2023 that included the impact of certain permanent items which are not deductible for tax purposes.

Three Months Ended September 30, 2023 compared to Three Months Ended September 30, 2022.

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 172,611	$ 203,585	$ (30,974)	(15)%
Service revenue	45,511	48,594	(3,083)	(6)%
Electricity sales	3,849	9,711	(5,862)	(60)%
(Losses) gains on oil and gas sales derivatives	(103,282)	114,279	(217,561)	n/a
Marketing and other revenues	113	277	(164)	(59)%
Total revenues and other	$ 118,802	$ 376,446	$ (257,644)	(68)%

Revenues and Other

Oil, natural gas and NGL sales decreased by $31 million, or 15%, to approximately $173 million for the three months ended September 30, 2023 when compared to the three months ended September 30, 2022. The variance was driven by $23 million of lower oil prices, $4 million of lower gas prices, and $4 million of lower volumes.

Service revenue decreased by $3 million to $46 million for the three months ended September 30, 2023, compared to the three months ended September 30, 2022, due to a change in service mix and volume of services.

Electricity sales represent sales to utilities and decreased $6 million, or 60%, to $4 million for the three months ended September 30, 2023 when compared to the three months ended September 30, 2022. This decrease was due to lower sales volume from not running one of our cogeneration facilities for a portion of the third quarter of 2023.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement losses for the three months ended September 30, 2023 and September 30, 2022 were $12 million and $29 million, respectively. The quarter-over-quarter decrease in settlement losses was driven by lower oil prices relative to our derivative fixed prices in the third quarter of 2023 than that of the same period in 2022. Notional volumes were 14 mbbl/d in the third quarter of 2023 and 15 mbbl/d in the third quarter of 2022. The mark-to-market non-cash loss for the three months ended September 30, 2023 was $91 million and a gain of $143 million for the three months ended September 30, 2022. Because we are the floating price payer on these swaps, generally, period to period decreases (increases) in the associated price index create valuation gains (losses).

Marketing and other revenues, which included third-party marketing activities, were not material for the three months ended September 30, 2023 and September 30, 2022.

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 59,842	$ 79,141	$ (19,299)	(24)%
Costs of services	35,806	37,628	(1,822)	(5)%
Electricity generation expenses	1,479	6,055	(4,576)	(76)%
Transportation expenses	1,089	1,277	(188)	(15)%
Acquisition costs(1)	2,082	—	2,082	100 %
General and administrative expenses	20,987	23,388	(2,401)	(10)%
Depreciation, depletion and amortization	39,729	39,506	223	1 %
Taxes, other than income taxes	17,980	7,335	10,645	145 %
Gains on natural gas purchase derivatives	(8,425)	(28,942)	20,517	(71)%
Other operating (income) expenses	(505)	623	1,128	181 %
Total expenses and other	170,064	166,011	4,053	2 %
Other (expenses) income:				
Interest expense	(9,101)	(7,867)	(1,234)	16 %
Other, net	(42)	(24)	(18)	75 %
Total other expenses	(9,143)	(7,891)	(1,252)	16 %
(Loss) income before income taxes	(60,405)	202,544	(262,949)	(130)%
Income tax (benefit) expense	(15,343)	10,884	(26,227)	241 %
Net (loss) income	$ (45,062)	$ 191,660	$ (236,722)	(124)%
Adjusted EBITDA(2)	$ 69,829	$ 96,981	$ (27,152)	(28)%
Adjusted Net Income(2)	$ 11,831	$ 76,977	$ (65,146)	(85)%

(1) Consists of costs related to the Macpherson Acquisition.

(2) Adjusted EBITDA and Adjusted Net Income (Loss) are financial measures that are not calculated in accordance with GAAP. For definitions and a reconciliation to the Net Cash Provided by Operating Activities and Net Income (loss), please see "—Non-GAAP Financial Measures".

Expenses

Lease operating expenses, which do not include the effects of gas purchase hedges, decreased 24% or $19 million on an absolute dollar basis to $60 million for the third quarter of 2023 when compared to the third quarter of 2022. The decrease was the result of lower natural gas (fuel) costs for our California steam generation facilities due to a decline in fuel prices and reduced volume of gas purchased.

Cost of services decreased $2 million, or 5%, to $36 million for the third quarter of 2023 compared to the third quarter of 2022 primarily due to a change in mix and volume of services.

Electricity generation expenses decreased $5 million, or 76%, to $1 million for the three months ended September 30, 2023 compared to the same period in 2022 due to not running one of our cogeneration facilities a portion of the third quarter of 2023.

Gains and losses on natural gas purchase derivatives for the three months ended September 30, 2023 and September 30, 2022 resulted in a gain of $8 million and $29 million, respectively. Settlements for the three months ended September 30, 2023 were a loss of $7 million, or $3.06 per boe, and a gain of $14 million or $5.82 per boe for the three months ended September 30, 2022. The quarter-over-quarter change in settlements was due to a decline in natural gas index prices below the fixed price of settled positions. The mark-to-market non-cash gain for the three months ended September 30, 2023 and September 30, 2022 was $16 million and $15 million, respectively. Because we are the fixed price payer on these natural gas swaps, generally, period to period increases (decreases) in the associated price index create valuation gains (losses).

Transportation expenses were comparable for the periods presented.

Acquisition costs increased $2 million for the three months ended September 30, 2023 compared to the three months ended September 30, 2022, primarily due to legal and other professional expenses associated with the Macpherson Acquisition.

General and administrative expenses decreased $2 million or 10% in the three months ended September 30, 2023 when compared to the three months ended September 30, 2022. For the three months ended September 30, 2023 and September 30, 2022, general and administrative expenses included non-cash stock compensation costs of approximately $3 million, and $4 million, respectively. We incurred non-recurring costs of $1 million for the three months ended September 30, 2023 compared to none for the three months ended September 30, 2022.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs decreased $2 million for the three months ended September 30, 2023 compared to the three months ended September 30, 2022. The decrease was the result of cost savings initiatives that began in early 2023. See "—Non-GAAP Financial Measures" for a reconciliation of general and administrative expense, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General and Administrative Expenses.

DD&A remained flat at $40 million in the three months ended September 30, 2023 when compared to the three months ended September 30, 2022.

Taxes, Other Than Income Taxes

	Three Months Ended September 30,			
	2023	2022	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.47	$ 1.45	$ 0.02	1 %
Ad valorem and property taxes	2.12	1.48	0.64	43 %
Greenhouse gas allowances	4.14	0.17	3.97	2,335 %
Total taxes other than income taxes	$ 7.73	$ 3.10	$ 4.63	149 %

Taxes, other than income taxes increased 149% to $7.73 per boe for the three months ended September 30, 2023, compared to $3.10 per boe for the three months ended September 30, 2022. The GHG allowance expense increase was due to higher non-cash mark-to-market prices for the allowances in the third quarter of 2023. The increase in ad valorem and property taxes was due to an increase in property values when compared to the three months ended September 30, 2022.

Interest Expense

Interest expense increased $1 million, or 16%, in the three months ended September 30, 2023 when compared to the three months ended September 30, 2022 as we had higher working capital borrowings on the RBL Facility in 2023.

Income Taxes

Our effective tax rate was approximately 25% for the three months ended September 30, 2023 compared to approximately 5% for the three months ended September 30, 2022. The rate in the third quarter of 2023 was impacted by the book loss in the third quarter of 2023, which included the impact of certain permanent items that are not deductible for tax purposes. The rate in the third quarter of 2022 was impacted by the changes in the valuation allowance recorded against the deferred tax assets.

Nine Months Ended September 30, 2023 compared to Nine Months Ended September 30, 2022.

	Nine Months Ended September 30,			
	2023	2022	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 496,671	$ 654,007	$ (157,336)	(24)%
Service revenue	137,808	134,608	3,200	2 %
Electricity sales	12,372	22,549	(10,177)	(45)%
Losses on oil and gas sales derivatives	(43,912)	(88,237)	44,325	(50)%
Marketing and other revenues	194	731	(537)	(73)%
Total revenues and other	$ 603,133	$ 723,658	$ (120,525)	(17)%

Revenues and Other

Oil, natural gas and NGL sales decreased $157 million, or 24%, to $497 million for the nine months ended September 30, 2023 when compared to the nine months ended September 30, 2022. The variance was driven by a $134 million decrease in oil prices and a $25 million decrease in volumes, partially offset by a $2 million increase in gas prices.

Service revenue increased $3 million, or 2%, to $138 million for the nine months ended September 30, 2023 when compared to the nine months ended September 30, 2022, due to rate increases, which were effective in late 2022 to offset a portion of cost inflation, partially offset by a change in mix and volume of services.

Electricity sales, which represent sales to utilities, decreased $10 million, or 45%, to $12 million for the nine months ended September 30, 2023 when compared to the nine months ended September 30, 2022. The decrease was primarily due to lower sales volume as a result of not running one of our cogeneration facilities for most of 2023.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement losses for the nine months ended September 30, 2023 and September 30, 2022 were $22 million and $110 million, respectively. The period-over-period decrease in settlement losses was driven by a narrower spread between the settled derivative fixed prices and index oil prices in the nine months ended September 30, 2023 compared to the same period in 2022. The mark-to-market non-cash loss was $22 million for the nine months ended September 30, 2023 and a gain of $22 million for the nine months ended September 30, 2022. Because we are the floating price payer on these swaps, generally, period to period decreases (increases) in the associated price index create valuation gains (losses).

Marketing and other revenues were not material for the nine months ended September 30, 2023 and September 30, 2022.

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 249,384	$ 214,720	$ 34,664	16 %
Costs of services	108,988	107,809	1,179	1 %
Electricity generation expenses	5,252	16,640	(11,388)	(68)%
Transportation expenses	3,226	3,543	(317)	(9)%
Marketing expenses	—	299	(299)	(100)%
Acquisition costs[(1)]	3,054	—	3,054	100 %
General and administrative expenses	75,144	69,513	5,631	8 %
Depreciation, depletion and amortization	119,605	117,338	2,267	2 %
Taxes, other than income taxes	42,147	25,154	16,993	68 %
Losses (gains) on natural gas purchase derivatives	4,989	(47,335)	52,324	n/a
Other operating (income) expenses	(1,824)	4,745	(6,569)	138 %
Total expenses and other	609,965	512,426	97,539	19 %
Other (expenses) income:				
Interest expense	(25,732)	(23,271)	(2,461)	11 %
Other, net	(227)	(79)	(148)	187 %
Total other expenses	(25,959)	(23,350)	(2,609)	11 %
(Loss) income before income taxes	(32,791)	187,882	(220,673)	(117)%
Income tax (benefit) expense	(7,640)	9,678	(17,318)	179 %
Net (loss) income	$ (25,151)	$ 178,204	$ (203,355)	(114)%
Adjusted EBITDA[(2)]	$ 198,221	$ 302,440	$ (104,219)	(34)%
Adjusted Net Income[(2)]	$ 28,804	$ 150,015	$ (121,211)	(81)%

(1) Consists of costs related to the Macpherson Acquisition.

(2) Adjusted EBITDA and Adjusted Net Income (Loss) are financial measures that are not calculated in accordance with GAAP. For definitions and a reconciliation to the Net Cash Provided by Operating Activities and Net Income (loss), please see "—Non-GAAP Financial Measures".

Expenses

Lease operating expenses, which do not include the effects of gas purchase hedges, increased 16%, or $35 million, on an absolute dollar basis to $249 million for the nine months ended September 30, 2023 when compared to the nine months ended September 30, 2022. Approximately 68% of this increase was the result of higher natural gas (fuel) prices for our California steam facilities. Lease operating expenses excluding fuel increased $11 million due to higher power costs and weather-related outside services and lease maintenance expenses.

Cost of services increased $1 million, or 1%, to $109 million in the nine months ended September 30, 2023, due to annual wage increases and higher staffing levels. Cost of services in the nine months ended September 30, 2022 consisted entirely of costs from the well servicing and abandonment business.

Electricity generation expenses decreased $11 million to $5 million for the nine months ended September 30, 2023 compared to the same period in 2022 due to lower volumes sold as a result of not running one of our cogeneration facilities for most of 2023. 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, 2023 and September 30, 2022 consisted of a loss of $5 million and a gain of $47 million, respectively. The settlement gain for the nine months ended September 30, 2023 was $37 million, or $5.39 per boe, compared to a gain of $26 million, or $3.58 per boe, for the same period in 2022, driven by higher gas prices relative to the fixed prices of settled positions in 2023 compared to that of 2022. The mark-to-market valuation for the nine months ended September 30, 2023 was a loss of $42 million compared to a gain of $22 million for the same period in 2022 due to lower futures prices relative to our derivative fixed prices at September 30, 2023 compared to those at September 30, 2022. Because we are the fixed price payer on these natural gas swaps, generally, period to period increases (decreases) in the associated price index create valuation gains (losses).

Transportation expenses were comparable for the periods presented.

Marketing expenses were not material for the periods presented.

Acquisition costs increased $3 million for the nine months ended September 30, 2023 compared to the nine months ended September 30, 2022, to the legal and professional expenses associated with the Macpherson Acquisition.

General and administrative expenses increased $6 million, or 8%, to approximately $75 million for the nine months ended September 30, 2023 compared to the nine months ended September 30, 2022. For the nine months ended September 30, 2023 and September 30, 2022, general and administrative expenses included non-cash stock compensation costs of approximately $11 million and $12 million, respectively. We incurred non-recurring costs of $9 million for the nine months ended September 30, 2023, related to executive transition costs, workforce reduction costs and shareholder litigation expenses. Non-recurring costs were not significant in the same period in 2022.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased $1 million, or 3%, to $56 million for the nine months ended September 30, 2023 compared to the nine months ended September 30, 2022 due to cost saving initiatives implemented in early 2023. See “—Non-GAAP Financial Measures” for a reconciliation of general and administrative expense, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General and Administrative Expenses.

DD&A increased $2 million, or 2%, to $120 million for the nine months ended September 30, 2023 compared to the nine months ended September 30, 2022 due to an increase in depletion rates.

Taxes, Other Than Income Taxes

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.56	$ 1.42	$ 0.14	10 %
Ad valorem and property taxes	2.06	1.49	0.57	38 %
Greenhouse gas allowances	2.50	0.60	1.90	317 %
Total taxes other than income taxes	$ 6.12	$ 3.51	$ 2.61	74 %

Taxes, other than income taxes increased 74% to $6.12 per boe for the nine months ended September 30, 2023 compared to $3.51 per boe for the nine months ended September 30, 2022. GHG allowance expense increased due to higher non-cash mark-to-market prices for the allowances compared to the same period in 2022. Ad valorem taxes increased due to additional wells coming online and an increase in property values. Severance taxes increased due to an increase in the California conservation tax rate, partially offset by utilization of Utah tax credits.

Other Operating (Income) Expenses

For the nine months ended September 30, 2023, other operating income was $2 million and mainly consisted of net property tax refunds from prior periods and a net gain on equipment sales. For the nine months ended September 30, 2022, other operating expenses were $5 million and mainly consisted of over $2 million in royalty audit charges incurred prior to our emergence and restructuring in 2017 and approximately $2 million loss on the divestiture of the Piceance properties.

Interest Expense

Interest expense increased $2 million, or 11%, in the nine months ended September 30, 2023 compared to the same period in 2022 as a result of higher working capital borrowings on the RBL Facility in 2023.

Income Taxes

Our effective tax rate was approximately 23% for the nine months ended September 30, 2023, compared to 5% for the nine months ended September 30, 2022, respectively. The rate for the nine months ended September 30, 2023 was impacted by the book loss in the third quarter of 2023, which included the impact of certain permanent items that are not deductible for tax purposes. The rate for the nine months ended September 30, 2022 was impacted by changes in the valuation allowance recorded against deferred tax assets.

E&P Field Operations

Overall, management assesses the efficiency of our E&P field operations by considering core E&P operating expenses together with our cogeneration, marketing and transportation activities. In particular, a core component of our E&P operations in California is steam, which we use to lift heavy oil to the surface. We operate several cogeneration facilities to produce some of the steam needed in our operations. In comparing the cost effectiveness of our cogeneration plants against other sources of steam in our operations, management considers the cost of operating the cogeneration plants, including the cost of the natural gas purchased to operate the facilities, against the value of the steam and electricity used in our E&P field operations and the revenues we receive from sales of excess electricity to the grid. We strive to minimize the variability of our fuel gas costs for our California steam operations with natural gas purchase hedges. Consequently, the efficiency of our E&P field operations are impacted by the cash settlements we receive or pay from these derivatives. We also have contracts for the transportation of fuel gas from the Rockies which has historically been cheaper than the California markets. With respect to transportation and marketing, management also considers opportunistic sales of incremental capacity in assessing the overall efficiencies of E&P operations.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Electricity generation expenses include the portion of fuel, labor, maintenance, and tools and supplies from two of our cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to our costs to transport the oil and gas that we produce within our properties or move it to the market. Marketing 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. Electricity revenue is from the sale of excess electricity from two of our cogeneration facilities to a California utility company under long-term contracts at market prices. These cogeneration facilities are sized to satisfy the steam needs in their respective fields, but the corresponding electricity produced is more than the electricity that is currently required for the operations in those fields. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

	Three Months Ended		$ Change	% Change
	September 30, 2023	June 30, 2023		
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 25.73	$ 23.17	$ 2.56	11 %
Electricity generation expenses	0.64	0.54	0.10	19 %
Transportation expenses	0.47	0.46	0.01	2 %
Total	$ 26.84	$ 24.17	$ 2.67	11 %
Cash settlements paid for gas purchase hedges	$ 3.06	$ 4.56	$ (1.50)	(33)%
E&P non-production revenues				
Electricity sales	$ 1.65	$ 1.30	$ 0.35	27 %
Transportation sales	0.05	0.02	0.03	150 %
Total	$ 1.70	$ 1.32	$ 0.38	29 %

	Three Months Ended		$ Change	% Change
	September 30, 2023	September 30, 2022		
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 25.73	$ 33.40	$ (7.67)	(23)%
Electricity generation expenses	0.64	2.56	(1.92)	(75)%
Transportation expenses	0.47	0.54	(0.07)	(13)%
Total	$ 26.84	$ 36.50	$ (9.66)	(26)%
Cash settlements paid (received) for gas purchase hedges	$ 3.06	$ (5.82)	$ 8.88	(153)%
E&P non-production revenues				
Electricity sales	$ 1.65	$ 4.10	$ (2.45)	(60)%
Transportation sales	0.05	0.12	(0.07)	(58)%
Total	$ 1.70	$ 4.22	$ (2.52)	(60)%

	Nine Months Ended			
	September 30, 2023	September 30, 2022	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 36.28	$ 29.99	$ 6.29	21 %
Electricity generation expenses	0.76	2.32	(1.56)	(67)%
Transportation expenses	0.47	0.49	(0.02)	(4)%
Marketing expenses	—	0.04	(0.04)	(100)%
Total	$ 37.51	$ 32.84	$ 4.67	14 %
Cash settlements received for gas purchase hedges	$ (5.39)	$ (3.58)	$ (1.81)	51 %
E&P non-production revenues				
Electricity sales	$ 1.80	$ 3.15	$ (1.35)	(43)%
Transportation sales	0.03	0.06	(0.03)	(50)%
Marketing revenues	—	0.04	(0.04)	(100)%
Total	$ 1.83	$ 3.25	$ (1.42)	(44)%

Non-GAAP Financial Measures

Adjusted EBITDA, Adjusted 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), Adjusted Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either net income (loss) or cash flow, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses 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 unusual and infrequent items. 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. We also use Adjusted EBITDA in planning our capital allocation to sustain production levels and to determine our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility.

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, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our statutory tax rate. 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 believe Adjusted Net Income (Loss) is useful to investors because it reflects how management evaluates the Company’s ongoing financial and operating performance from period-to-period after removing certain transactions and activities that affect comparability of the metrics and are not reflective of the Company’s core operations. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

We define Adjusted Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and maintenance capital. Maintenance capital represents the capital expenditures needed to maintain substantially the same volume of annual oil and gas production and is defined as capital expenditures, excluding, when applicable, E&P capital expenditures that are related to strategic business expansion, such as acquisitions of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes and capital expenditures in our well servicing and abandonment and corporate segments that are related to ancillary sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. Management believes Adjusted Free Cash Flow may be useful in an investor analysis of our ability to generate cash from operating activities from our existing oil and gas asset base after maintaining the existing production volumes of that asset base to return capital to stockholders, fund further business expansion through acquisitions or investments in our existing asset base to increase production volumes and pay other non-discretionary expenses. Management also uses Adjusted Free Cash Flow as the primary metric to plan for future growth and expects to use approximately (a) 80% of Adjusted Free Cash Flow for debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets and (b) 20% in the form of variable dividends.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, strategic acquisitions or other growth opportunities, or other discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from this measure.

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 believe Adjusted General and Administrative Expenses is useful to investors because it reflects how management evaluates the Company's ongoing general and administrative expenses from period-to-period after removing non-cash stock compensation, as well as unusual or infrequent costs that affect comparability of the metrics and are not reflective of the Company's administrative costs. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

While Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses 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 and should not be considered as an alternative to, or more meaningful than 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 Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

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

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
			(in thousands)		
Adjusted EBITDA reconciliation:					
Net (loss) income	$ (45,062)	$ 25,770	$ 191,660	$ (25,151)	$ 178,204
Add (Subtract):					
Interest expense	9,101	8,794	7,867	25,732	23,271
Income tax (benefit) expense	(15,343)	10,616	10,884	(7,640)	9,678
Depreciation, depletion and amortization	39,729	39,755	39,506	119,605	117,338
Losses (gains) on derivatives	94,857	(6,847)	(143,221)	48,901	40,902
Net cash (paid) received for scheduled derivative settlements	(19,432)	(12,524)	(14,739)	15,511	(84,519)
Other operating (income) expenses	(505)	(1,033)	623	(1,824)	4,745
Stock compensation expense	3,018	3,552	4,401	11,336	12,623
Acquisition costs[(1)]	2,082	972	—	3,054	—
Non-recurring costs[(2)]	1,384	—	—	8,697	198
Adjusted EBITDA	$ 69,829	$ 69,055	$ 96,981	$ 198,221	$ 302,440

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
			(in thousands)		
Adjusted EBITDA reconciliation:					
Net cash provided by operating activities	$ 55,320	$ 62,538	$ 95,762	$ 119,639	$ 255,534
Add (Subtract):					
Cash interest payments	15,065	1,004	14,493	30,457	29,481
Cash income tax payments	2,087	670	321	2,757	2,805
Non-recurring costs[(2)]	1,384	—	—	8,697	198
Changes in operating assets and liabilities - working capital[(3)]	(3,032)	6,065	(14,151)	39,778	9,557
Other operating (income) expenses - cash portion[(4)]	(995)	(1,222)	556	(3,107)	4,865
Adjusted EBITDA	$ 69,829	$ 69,055	$ 96,981	$ 198,221	$ 302,440

(1) Consists of costs related to the Macpherson Acquisition.

(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter.

(3) Changes in other assets and liabilities consists of working capital and various immaterial items.

(4) Represents the cash portion of other operating (income) expenses from the income statement, net of the non-cash portion in the cash flow statement.

The following table presents a reconciliation of the GAAP financial measure of operating cash flow to the non-GAAP financial measure of Adjusted Free Cash Flow for each of the periods indicated. We use Adjusted Free Cash Flow for our shareholder return model, which began in 2022.

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
			(in thousands)		
Adjusted Free Cash Flow reconciliation:					
Net cash provided by operating activities[(1)]	$ 55,320	$ 62,538	$ 95,762	$ 119,639	$ 255,534
Subtract:					
Maintenance capital[(2)]	(10,833)	(19,625)	(38,312)	(49,730)	(96,883)
Fixed dividends[(3)]	(9,080)	(9,139)	(4,726)	(27,409)	(14,688)
Adjusted Free Cash Flow	$ 35,407	$ 33,774	$ 52,724	$ 42,500	$ 143,963

(1) On a consolidated basis.

(2) Maintenance capital is the capital required to keep annual production substantially flat, and is calculated as follows:

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
			(in thousands)		
Consolidated capital expenditures[(a)]	$ (13,596)	$ (21,895)	$ (40,817)	$ (56,124)	$ (102,523)
Excluded items[(b)]	2,763	2,270	2,505	6,394	5,640
Maintenance capital	$ (10,833)	$ (19,625)	$ (38,312)	$ (49,730)	$ (96,883)

(a) Capital expenditures include capitalized overhead and interest and excludes acquisitions and asset retirement spending.

(b) Comprised of the capital expenditures in our E&P segment that are related to strategic business expansion, such as acquisitions of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes and capital expenditures in our well servicing and abandonment segment and corporate expenditures that are related to ancillary sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. For the three months ended September 30, 2023, June 30, 2023, and September 30, 2022, we excluded approximately $2.1 million, $1.3 million, and $1.7 million of capital expenditures related to our well servicing and abandonment segment, respectively, which was substantially all used for sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. For the three months ended September 30, 2023, June 30, 2023, and September 30, 2022, we excluded approximately $0.7 million, $0.9 million, and $0.8 million of corporate capital expenditures, respectively, which we determined was not related to the maintenance of our baseline production. For the nine months ended September 30, 2023 and 2022, we excluded approximately $4.4 million and $3.4 million of capital expenditures related to our well servicing and abandonment segment, which was substantially all used for sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of our core business. For the nine months ended September 30, 2023 and 2022, we excluded approximately $2.0 million and $2.3 million, respectively, of corporate capital expenditures, which we determined was not related to the maintenance of our baseline production.

(3) Represents fixed dividends declared for the periods presented.

The following table presents a reconciliation of the GAAP financial measures of net income (loss) and net income (loss) per share — diluted to the non-GAAP financial measures of Adjusted Net Income (Loss) and Adjusted Net Income (Loss) per share — diluted for each of the periods indicated.

	Three Months Ended					
	September 30, 2023		June 30, 2023		September 30, 2022	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted	(in thousands)	per share - diluted
Adjusted Net Income (Loss) reconciliation:						
Net (loss) income	$ (45,062)	$ (0.58)	$ 25,770	$ 0.33	$ 191,660	$ 2.34
Add (Subtract):						
Losses (gains) on derivatives	94,857	1.22	(6,847)	(0.09)	(143,221)	(1.75)
Net cash (paid) received for scheduled derivative settlements	(19,432)	(0.25)	(12,524)	(0.16)	(14,739)	(0.18)
Other operating (income) expenses	(505)	(0.01)	(1,033)	(0.01)	623	0.01
Acquisition costs[(1)]	2,082	0.03	972	0.01	—	—
Non-recurring costs[(2)]	1,384	0.02	—	—	—	—
Total additions (subtractions), net	78,386	1.01	(19,432)	(0.25)	(157,337)	(1.92)
Income tax (benefit) expense of adjustments[(3)]	(21,493)	(0.28)	5,328	0.07	42,654	0.52
Adjusted Net Income	$ 11,831	$ 0.15	$ 11,666	$ 0.15	$ 76,977	$ 0.94
Basic EPS on Adjusted Net Income	$ 0.16		$ 0.15		$ 0.99	
Diluted EPS on Adjusted Net Income	$ 0.15		$ 0.15		$ 0.94	
Weighted average shares of common stock outstanding - basic	75,662		76,721		78,044	
Weighted average shares of common stock outstanding - diluted	77,606		79,285		82,045	

(1) Consists of costs related to the Macpherson Acquisition.

(2) Consists of costs related to the settlement of shareholder litigation.

(3) The federal and state statutory rates were utilized in both 2023 and 2022. We updated the disclosure in 2022 to reflect the 2022 statutory rate, instead of the effective tax rate previously utilized.

	Nine Months Ended			
	September 30, 2023		September 30, 2022	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted
Adjusted Net Income (Loss) reconciliation:				
Net (loss) income	$ (25,151)	$ (0.32)	$ 178,204	$ 2.13
Add (Subtract):				
Losses on derivatives	48,901	0.63	40,902	0.49
Net cash received (paid) for scheduled derivative settlements	15,511	0.20	(84,519)	(1.01)
Other operating (income) expenses	(1,824)	(0.03)	4,745	0.06
Acquisition costs[1]	3,054	0.04	—	—
Non-recurring costs[2]	8,697	0.11	198	—
Total additions (subtractions), net	74,339	0.95	(38,674)	(0.46)
Income tax expense of adjustments[3]	(20,384)	(0.26)	10,485	0.13
Adjusted Net Income	$ 28,804	$ 0.37	$ 150,015	$ 1.80
Basic EPS on Adjusted Net Income	$ 0.38		$ 1.89	
Diluted EPS on Adjusted Net Income	$ 0.37		$ 1.80	
Weighted average shares of common stock outstanding - basic	76,163		79,304	
Weighted average shares of common stock outstanding - diluted	78,090		83,472	

(1) Consists of costs related to the Macpherson Acquisition.

(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter.

(3) The federal and state statutory rates were utilized in both 2023 and 2022. We updated the disclosure in 2022 to reflect the 2022 statutory rate, instead of the effective tax rate previously utilized.

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

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
			(in thousands)		
Adjusted General and Administrative Expense reconciliation:					
General and administrative expenses	$ 20,987	$ 22,488	$ 23,388	$ 75,144	$ 69,513
Subtract:					
Non-cash stock compensation expense (G&A portion)	(2,840)	(3,379)	(4,281)	(10,838)	(12,250)
Non-recurring costs(1)	(1,384)	—	—	(8,697)	(198)
Adjusted general and administrative expenses	$ 16,763	$ 19,109	$ 19,107	$ 55,609	$ 57,065
Well servicing and abandonment segment	$ 2,910	2,958	3,324	$ 8,994	$ 9,679
E&P segment, and corporate	$ 13,853	$ 16,151	$ 15,783	$ 46,615	$ 47,386
E&P segment, and corporate ($/boe)	$ 5.96	$ 6.84	$ 6.66	$ 6.78	$ 6.62
Total mboe	2,326	2,361	2,369	6,874	7,160

(1) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter.

Liquidity and Capital Resources

As of September 30, 2023, we had liquidity of $163 million, consisting of $17 million cash, $133 million available for borrowings under our 2021 RBL Facility and $13 million available for borrowings under our 2022 ABL Facility (as defined below). We also have $400 million in aggregate principal amount of 7% senior unsecured notes due February 2026 (the “2026 Notes”) outstanding as further discussed below. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund the remainder of our 2023 capital development programs from cash flow from operations.

In early February 2023, we updated our shareholder return model, including the plan to double our quarterly fixed dividend to $0.12 per share. We also modified the allocations of Adjusted Free Cash Flow. Our goal is to continue maximizing shareholder value through overall returns. In 2023, the annual cumulative allocation of Adjusted Free Cash Flow is intended to be (a) 80% primarily in the form of debt repurchases, stock repurchases, strategic growth, and acquisitions of producing bolt-on assets; and (b) 20% in the form of variable dividends. Any dividends (fixed or variable) actually paid will be determined by our Board of Directors in light of then existing conditions and circumstances, including our earnings, financial condition, restrictions in financing agreements, business conditions and other factors. From time to time we consider bolt-on acquisitions, which may be used to maintain our existing production volumes and could be at least partially funded out of maintenance capital, or may support strategic growth, in which case they would be funded from the 80% portion of our target Adjusted Free Cash Flow. Consistent with our shareholder return model, Berry views the Macpherson Acquisition, in part, as a means of maintaining base production and expects to reallocate $30 to $35 million of planned 2023 capital expenditures to the purchase price, which will be deducted from Adjusted Free Cash Flow in 2023, as part of our maintenance capital for 2023. The remainder of the purchase price will be allocated from Adjusted Free Cash Flow consistent with our shareholder return model allocation. A portion of the closing price was initially funded by drawing down the 2021 RBL Credit Facility.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, strategic acquisitions or other growth opportunities, or other discretionary expenditures, since we have non-discretionary expenditures that are not deducted from this measure. Adjusted Free Cash Flow is a non-GAAP financial measure. See “Management’s Discussion and Analysis—Non-GAAP Financial Measures” for a reconciliation of the GAAP financial measure of operating cash flow, our most directly comparable financial measure calculated and presented in accordance with GAAP, to the non-GAAP financial measure of Adjusted Free Cash Flow.

We currently believe that our liquidity, capital resources and existing cash will be sufficient to conduct our business and operations for at least the next 12 months. 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 Adjusted 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” of this Quarterly Report and Part I, Item 1A “Risk Factors” of our most recent Annual Report 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

The borrowing base under the 2021 RBL Facility is redetermined semi-annually, and the 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. On May 10, 2023, Berry Corp, as a guarantor, and Berry LLC, as borrower, entered into the Fourth Amendment to Credit Agreement (the “Amendment”) pursuant to which, among other things, the requisite lenders under the 2021 RBL Facility agreed to (i) maintain the aggregate elected commitment amounts at $200 million, (ii) decrease the borrowing base from $250 million to $200 million, which constituted a redetermination of the borrowing base that was scheduled to occur on or about May 1, 2023 pursuant to the terms of the Credit Facility, (iii) decrease the maximum consolidated leverage ratio by 0.25x to 2.75x for fiscal quarters ending June 30, 2023 and thereafter and (iv) amend the minimum hedging covenant to specify the floor price set forth in the Amendment but without any modification to the minimum volumes required to be hedged.

As of September 30, 2023, the 2021 RBL Facility had a $500 million revolving commitment and the aforementioned $200 million borrowing base and aggregate elected commitment and a $20 million sublimit for the issuance of letters of credit (with borrowing availability being reduced by the face amount of any letters of credit issued under the subfacility). Availability under the 2021 RBL Facility may not exceed the lesser of the aggregate elected commitments or the borrowing base less outstanding advances and letters of credit. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. The 2021 RBL Facility is available to us for general corporate purposes, including working capital.

The outstanding borrowings under the 2021 RBL Facility bear interest at a rate equal to, at our option, either (a) a customary base rate plus an applicable margin ranging from 2.0% to 3.0% or (b) a term SOFR reference rate, plus an applicable margin ranging from 3.0% to 4.0%, in each case determined based on the utilization level under the 2021 RBL Facility. Interest rate on base borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on term SOFR borrowings accrues in respect of interest periods of one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days and is payable on the last day of such interest period (or, for interest periods of six months, three months after the commencement of such interest period and at the end of such interest period). Unused commitment fees are charged at a rate of 0.50%.

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 2.75 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of September 30, 2023, we were in compliance with all of the debt covenants.

The 2021 RBL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If we do not comply with the financial and other covenants in the 2021 RBL Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the 2021 RBL Facility and terminate the commitments thereunder.

As of September 30, 2023, we had $57 million borrowings outstanding, $10 million in letters of credit outstanding and approximately $133 million of available borrowing capacity under the 2021 RBL Facility. As of October 31, 2023, we reduced the borrowings to $49 million.

2022 ABL Facility

Subject to satisfaction of customary conditions precedent to borrowing, as of September 30, 2023, C&J and C&J Management could borrow up to the lesser of (x) $15 million and (y) the borrowing base under the 2022 ABL Facility, with a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $7.5 million (with borrowing availability being reduced by the face amount of any letters of credit issued under the subfacility). The “borrowing base” is an amount equal to 80% of the balance due on eligible accounts receivable, subject to reserves that the lender may implement in its reasonable discretion. As of September 30, 2023, the borrowing base was $15 million. Interest on the outstanding principal amount of the revolving loans under the 2022 ABL Facility accrues at a per annum rate equal to 1.25% in excess of The Wall Street Journal Prime Rate. The “Wall Street Journal Prime Rate” is the variable rate of interest, on a per annum basis, which is announced and/or published in the “Money Rates” section of The Wall Street Journal from time to time as its “Prime Rate”. The rate will be redetermined whenever The Wall Street Journal Prime Rate changes. Interest is due quarterly, in arrears. The 2022 ABL Facility matures on June 5, 2025, unless terminated in accordance with the 2022 ABL Facility terms.

The 2022 ABL Facility requires CJWS to comply with the following financial covenants (i) maintain on a consolidated basis a ratio of total liabilities to tangible net worth of no greater than 1.5 to 1.0 at any time; (ii) reduce the amount of revolving advances outstanding under the 2022 ABL Facility to not more than 90% of the lesser of (a) the maximum revolving advance amount or (b) the borrowing base, as of the lender’s close of business on the last day of each fiscal quarter; and (iii) maintain net income before taxes of not less than $1.00 as of each fiscal year end. As of September 30, 2023, CJWS was in compliance with all of the debt covenants.

The 2022 ABL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If CJWS does not comply with the financial and other covenants in the 2022 ABL Facility, the lender may, subject to customary cure rights, require immediate payment of all amounts outstanding under the 2022 ABL Facility and terminate the commitment thereunder. CJWS’s obligations under the 2022 ABL Facility are not guaranteed by Berry Corp. or Berry LLC and Berry Corp. and Berry LLC do not and are not required to provide any credit support for such obligations.

In March 2023, we entered into the Amendment to Revolving Loan and Security Agreement (the “First Amendment”). The First Amendment, in addition to other changes described therein, amended the 2022 ABL Facility to substitute certain collateral.

As of September 30, 2023, CJWS had no borrowings and $2 million letters of credit outstanding with $13 million of available borrowing capacity under the 2022 ABL Facility.

Senior Unsecured Notes

In February 2018, Berry LLC completed a private issuance of $400 million in aggregate principal amount of 7.0% senior unsecured notes due February 2026, which resulted in net proceeds to us of approximately $391 million after deducting expenses and the initial purchasers’ discount.

The 2026 Notes are Berry LLC’s senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. The 2026 Notes are fully and unconditionally guaranteed on a senior unsecured basis by Berry Corp.

The indenture governing the 2026 Notes contains customary covenants and events of default (in some cases, subject to grace periods). We were in compliance with all covenants under the 2026 Notes as of September 30, 2023.

Debt Repurchase Program

In February 2020, the board of directors (the “Board of Directors” or the “Board”) 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 notes under this program.

Hedging

We have protected a significant portion of our anticipated cash flows through our commodity hedging program, including swaps, puts, calls and collars. 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 October 31, 2023, we had the following crude oil production and gas purchases hedges.

	Q4 2023	FY 2024	FY 2025	FY 2026
Brent - Crude Oil production				
Swaps				
Hedged volume (bbls)	1,407,600	5,426,817	1,847,125	645,768
Weighted-average price ($/bbl)	$ 77.61	$ 77.82	$ 75.21	$ 69.43
Sold Calls(1)				
Hedged volume (bbls)	368,000	732,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 106.00	$ 105.00	$ 91.11	$ 85.53
Purchased Puts (net)(2)				
Hedged volume (bbls)	552,000	1,281,000	365,000	—
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ 50.00	$ —
Purchased Puts (net)(2)				
Hedged volume (bbls)	—	—	2,121,127	1,251,500
Weighted-average price ($/bbl)	$ —	$ —	$ 60.00	$ 60.00
Sold Puts (net)(2)				
Hedged volume (bbls)	154,116	183,000	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ —	$ —
Henry Hub - Natural Gas purchases				
NWPL - Natural Gas purchases				
Swaps				
Hedged volume (mmbtu)	3,680,000	10,980,000	6,080,000	—
Weighted-average price ($/mmbtu)	$ 5.34	$ 4.21	$ 4.27	$ —
Gas Basis Differentials				
NWPL/HH - Natural Gas Purchases				
Hedged volume (mmbtu)	610,000	—	—	—
Weighted-average price ($/mmbtu)	$ 1.12	$ —	$ —	$ —

(1) Purchased calls and sold calls with the same strike price have been presented on a net basis.

(2) Purchased puts and sold puts with the same strike price have been presented on a net basis.

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

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	September 30, 2023	September 30, 2022
Crude Oil (per bbl):					
Realized sales price, before the effects of derivative settlements	$ 78.89	$ 70.68	$ 89.54	$ 74.72	$ 95.83
Effects of derivative settlements	$ (5.76)	$ (0.81)	$ (13.13)	$ (3.38)	$ (16.81)
Realized sales price, after the effects of derivatives	$ 73.13	$ 69.87	$ 76.41	$ 71.34	$ 79.02
Purchased Natural Gas (per mmbtu):					
Purchase price, before the effects of derivative settlements	$ 4.18	$ 3.44	$ 8.16	$ 9.22	$ 7.24
Effects of derivative settlements	$ 1.43	$ 2.20	$ (2.53)	$ (2.56)	$ (1.53)
Purchase price, after the effects of derivatives settlements	$ 5.61	$ 5.64	$ 5.63	$ 6.66	$ 5.71

Cash Dividends

In February 2023, the Board of Directors declared regular fixed cash dividends of $0.06 per share, as well as variable cash dividends of $0.44 per share which was based on the results of the fourth quarter of 2022, for a total of $0.50 per share, which was paid in March 2023. In April 2023, the Board of Directors declared a $0.12 per share regular fixed cash dividend based on the results of the first quarter of 2023, which was paid in May 2023. In July 2023, the Board of Directors declared a $0.12 per share regular fixed cash dividend, as well as a variable dividend of $0.02 based on the results for the six months ended June 30, 2023, which was paid in August 2023. In October 2023, the Board of Directors approved a $0.12 per share regular fixed cash dividend, as well as a variable dividend of $0.09 based on the results of the third quarter of 2023, each of which is expected to be paid in November 2023.

The following table represents the regular fixed cash dividends on our common stock and variable dividends approved by our Board of Directors in 2023.

	First Quarter	Second Quarter	Third Quarter	Year-to-Date
Fixed Dividends	$ 0.12	$ 0.12	$ 0.12	$ 0.36
Variable Dividends[(1)]	—	0.02	0.09	0.11
Total	$ 0.12	$ 0.14	$ 0.21	$ 0.47

(1) Variable Dividends are declared the quarter following the period of results (the period used to determine the variable divided based on the shareholder return model). The table notes total dividends earned in each quarter. In October 2023, the Board of Directors approved a $0.09 variable dividend based on the results for the three months ended September 30, 2023.

The Company anticipates that it will continue to pay quarterly cash dividends in the future. However, the payment and amount of future dividends remain within the discretion of the Board and will depend upon the Company's future earnings, financial condition, capital requirements and other factors.

Stock Repurchase Program

The Company did not repurchase any shares during the three months ended September 30, 2023. For the nine months ended September 30, 2023, we repurchased 1.4 million shares (all in the second quarter) for approximately $10 million. As of September 30, 2023, the Company had repurchased a total of 11,949,247 shares under the stock repurchase program for approximately $114 million in aggregate. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company intends to allocate a portion of Adjusted Free Cash Flow to opportunistic share repurchases.

In February 2023, the Board of Directors approved an increase of $102 million to the Company’s stock repurchase authorization bringing the Company’s remaining share authority to $200 million. As of September 30, 2023, the Company’s remaining total share repurchase authority is $190 million. The Board’s authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions, subject to market conditions and other factors, up to the aggregate amount authorized by the Board. The Board’s authorization has no expiration date.

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. Purchases may be commenced or suspended at any time without notice and do not obligate the company to purchase shares during any period or at all. Any shares repurchased are reflected as treasury stock and any shares acquired will be available for general corporate purposes.

Macpherson Acquisition

In July 2023, we executed an agreement to acquire Macpherson Energy, a privately held Kern County, California operator and we closed the acquisition in September 2023. The total purchase price is approximately $70 million, subject to customary purchase price adjustments. The transaction was structured such that approximately $53 million has been paid at closing, including purchase price adjustments, and approximately $20 million will be paid in July 2024, subject to purchase price adjustments.

Consistent with our shareholder return model, Berry views this acquisition, in part, as a means of maintaining base production and expects to reallocate $30 to $35 million of planned 2023 capital expenditures to the purchase price, which will be deducted from maintenance capital in Adjusted Free Cash Flow for 2023. The remainder of the purchase price will be allocated from Adjusted Free Cash Flow consistent with our shareholder return model allocation. A portion of the closing price was initially funded by drawing down the 2021 RBL Credit Facility.

The Macpherson Energy assets are considered high-quality, low decline oil producing properties that are closely located to existing Berry properties in rural Kern County, California. These assets also align with Berry’s stated strategy of acquiring accretive, producing bolt-ons. Macpherson Energy is reported under the E&P business segment.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Nine Months Ended September 30,	
	2023	2022
	(in thousands)	
Net cash:		
Provided by operating activities	$ 119,639	$ 255,534
Used in investing activities	(126,450)	(109,664)
Used in financing activities	(22,239)	(119,680)
Net (decrease) increase in cash and cash equivalents	$ (29,050)	$ 26,190

Operating Activities

Cash provided by operating activities decreased for the nine months ended September 30, 2023 by approximately $136 million when compared to the nine months ended September 30, 2022, primarily due to a decrease in revenue of $168 million (excluding CJWS), a decrease in working capital of $27 million, an increase in operating expenses of $23 million (excluding CJWS), an increase in taxes other than income taxes of $17 million and an increase in general and administrative expenses of $11 million (excluding CJWS), partially offset by an increase in derivative settlements received of $100 million, a decrease in other operating expenses (income) of $7 million, and an increase of $3 million related to net margin for CJWS.

Investing Activities

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

	Nine Months Ended September 30,	
	2023	2022
	(in thousands)	
Capital expenditures:		
Capital expenditures	$ (56,124)	$ (102,523)
Changes in capital expenditures accruals	(10,431)	14,129
Acquisitions, net of cash received	(59,895)	(21,270)
Net cash used in investing activities	$ (126,450)	$ (109,664)

Cash used in investing activities increased $17 million for the nine months ended September 30, 2023 when compared to the same period in 2022, primarily due to cash used for the Macpherson Acquisition of $51 million (net of cash received), offset by a decrease in cash used for capital expenditures and related accruals of $22 million and a $12 million decrease in cash used for acquisitions, net of cash received.

Financing Activities

Cash used in financing activities for the nine months ended September 30, 2023 was primarily for dividends paid of $62 million, for the purchase of treasury stock of $10 million, and for taxes on equity awards of $7 million, offset by $57 million in borrowings under the 2021 RBL credit facility. Cash used in financing activities in the same period in 2022 was primarily for dividends paid of $74 million, for the purchase of treasury stock of $42 million, and for taxes on equity awards of $4 million.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2022 to September 30, 2023 are discussed below.

	September 30, 2023		December 31, 2022	
	(in thousands)			
Cash and cash equivalents	$	17,200	$	46,250
Accounts receivable, net	$	102,794	$	101,713
Derivative instruments assets - current and long-term	$	—	$	36,443
Other current assets	$	37,697	$	33,725
Property, plant & equipment, net	$	1,390,543	$	1,359,813
Deferred income taxes asset - long-term	$	54,133	$	42,844
Other noncurrent assets	$	11,558	$	10,242
Accounts payable and accrued expenses	$	173,900	$	203,101
Derivative instruments liabilities - current and long-term	$	72,127	$	44,748
Long-term debt	$	453,667	$	395,735
Asset retirement obligations - long-term	$	159,764	$	158,491
Other noncurrent liabilities	$	46,348	$	28,470
Stockholders’ equity	$	708,119	$	800,485

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

The $4 million increase in other current assets was due to an increase of approximately $7 million in materials inventory purchases, partially offset by a $3 million decrease for the amortization of prepaid expenses.

The $31 million increase in property, plant and equipment was primarily due to an increase of year-to-date capital investment of $56 million and approximately $86 million in acquisition activity, partially offset by accumulated depreciation of $111 million.

The $11 million increase in deferred income taxes - long term was primarily due to the tax effect of the book loss in the third quarter.

The $29 million decrease in accounts payable and accrued expenses included decreases of $36 million in accrued expenses primarily for fuel gas purchases, $14 million in royalties payable and $6 million due to interest payments exceeding accrued interest, partially offset by an increase of $18 million for the discounted amount due in July 2024 for the Macpherson Acquisition, an increase of $5 million in taxes, other than income taxes, an increase of $3 million in trade payables and $1 million in the operating lease liability.

The $64 million increase in net derivative liability, which includes the derivative asset, is due to the increase in the net liability of $8 million at December 31, 2022 to $72 million as of September 30, 2023. 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 $58 million increase in long-term debt largely reflected borrowings on our 2021 RBL Facility made in connection with the Macpherson Acquisition as of September 30, 2023.

The $1 million increase in the long-term portion of the asset retirement obligations from $158 million at December 31, 2022 to $160 million at September 30, 2023 was due to $9 million of accretion expense and an increase of $7 million of liabilities from the Macpherson Acquisition, largely offset by $15 million of liabilities settled during the period.

The $18 million increase in other noncurrent liabilities was due to price increases related to greenhouse gas allowances.

The $92 million decrease in stockholders' equity was due to $62 million of common stock dividends declared, $25 million in net loss, $10 million in purchases of treasury stock, and $7 million of shares withheld for payment of taxes on equity awards, partially offset by $12 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, 2023 and December 31, 2022. 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, 2023, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matters

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Securities Class Action") 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 (collectively, the "Defendants"). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933 (as amended, the "Securities Act"), and Sections 10(b) and 20(a) of the Exchange Act of 1934 (as amended, the "Exchange Act"), on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company's 2018 IPO; or (ii) Berry Corp.'s securities between July 26, 2018 and November 3, 2020 (the "Class Period"). In particular, 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 November 3, 2020.

On November 1, 2021, the court-appointed 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 and Sections 10(b) and 20(a) of the Exchange Act, 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 filed a motion to dismiss on January 24, 2022 and on September 13, 2022, the court issued an order denying that motion, and the case moved into discovery. On February 13, 2023, the plaintiffs filed a motion for class certification, and on April 14, 2023, the defendants filed their opposition; the plaintiffs filed their reply on May 26, 2023, and a hearing on the motion for class certification was set for August 23, 2023.

On July 31, 2023, the parties executed a Memorandum of Understanding memorializing an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. On September 18, 2023, the plaintiffs and Defendants executed a Stipulation and Agreement of Settlement, and the plaintiffs filed a motion seeking preliminary approval of the settlement. On October 18, 2023, the Court granted that motion, issuing a preliminary approval order and scheduling a final settlement approval hearing for February 6, 2024. The parties will now move forward with the notice and approval process, which is expected to include, among other things, the February 6, 2024 final approval hearing, an opt-out process, and opportunities for class members to object to the settlement. The Defendants continue to maintain that the claims are without merit and admit no liability in connection with the settlement.

On October 20, 2022, a shareholder derivative lawsuit (the "Assad Lawsuit") was filed in the United States District Court for the Northern District of Texas by putative stockholder George Assad, allegedly on behalf of the Company, that piggy-backs on the Securities Class Action and which is currently pending before the same court. The derivative complaint names certain current and former officers and directors as defendants, and generally alleges that they breached their fiduciary duties by causing or failing to prevent the securities violations alleged in the securities class action. The derivative complaint also alleges claims for unjust enrichment as against all defendants, and claims for contribution and indemnification under Sections 10(b) and 21D of the Exchange Act. On January 27, 2023, the court granted the parties' joint stipulated request to stay the Assad Lawsuit pending resolution of the Securities Class Action.

On January 20, 2023, a second shareholder derivative lawsuit (the "Karp Lawsuit," together with the Assad Lawsuit, the "Shareholder Derivative Actions") was filed, this time in the United States District Court for the District of Delaware, by putative stockholder Molly Karp, allegedly on behalf of the Company, again piggy-backing on the Securities Class Action. This complaint, similar to the Assad Lawsuit, is brought against certain current and former officers and directors of the Company, asserting breach of fiduciary duty, aiding and abetting, and contribution claims based on the defendants allegedly having caused or failed to prevent the securities violations alleged in the securities class action. In addition, the complaint asserts a claim under Section 14(a) of the Exchange Act, alleging that Berry's 2022 proxy statement was false and misleading in that it suggested the Company's internal controls were sufficient and the Board of Directors was adequately overseeing material risks facing the Company when, according to the derivative plaintiff, that was not the case. On February 13, 2023, the court granted the parties' joint stipulated request to stay the Karp Lawsuit pending resolution of a motion for summary judgment by the defendants in the Securities Class Action. The proposed settlement of the Securities Class Action does not relate to the Shareholder Derivative Actions. The defendants continue to believe the claims in the Shareholder Derivative Actions are without merit and intend to defend vigorously against them, but there can be no assurances as to the outcome. At this time, we are unable to estimate the probability or the amount of liability, if any, related to these matters.

In addition, on or around April 17, 2023, the Company received a stockholder litigation demand that the Board of Directors investigate and commence legal proceedings against certain current and former officers and directors based ostensibly on the same claims asserted in the Shareholder Derivative Actions. The Board of Directors appointed a Demand Review Committee for the purpose of reviewing the demand.

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of September 30, 2023:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Off-Balance Sheet arrangements:[1]					
Transportation contracts[2]	$ 84,145	11,517	18,987	16,165	37,476
Other purchase obligations[3]	17,100	—	17,100	—	—
Total contractual obligations	$ 101,245	$ 11,517	$ 36,087	$ 16,165	$ 37,476

(1) These commitments and contractual obligations are expected to be funded by our cash flow from operations.

(2) 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 pipeline transportation of natural gas to market and between markets, as well as gathering and processing of natural gas.

(3) Amounts include a drilling commitment in California, for which we are required to drill 57 wells with a minimum commitment of $17.1 million by June 2025. In September 2023, the drilling commitment was amended to defer 28 of those wells to be drilled by December 2024 (previously required to be drilled by October 1, 2023), and the remaining 29 wells to be drilled by June 2025 (previously required to be drilled by June 1, 2024).

Critical Accounting Policies and Estimates

See Part II, Item 7 “Critical Accounting Policies and Estimates” in our most recent Annual Report.

Cautionary Note Regarding Forward-Looking Statements

The information included or incorporated by reference in this Quarterly Report includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. All statements other than statements of historical facts included in this Quarterly Report that address plans, activities, events, objectives, goals, strategies or developments that the Company expects, believes or anticipates will or may occur in the future, such as those regarding our financial position, liquidity, cash flows (including, but not limited to, Adjusted Free Cash Flow), financial and operating results, capital program and development and production plans, operations and business strategy, potential acquisition and other strategic opportunities, reserves, hedging activities, capital expenditures, return of capital, our shareholder return model and the payment of future dividends, future repurchases of stock or debt, capital investments, our ESG strategy and the initiation of new projects or business in connection therewith, recovery factors and other guidance, are forward-looking statements. These statements are based upon various assumptions, many of which are based, in turn, upon further assumptions. Although we believe that these assumptions were reasonable when made, these assumptions are inherently subject to significant uncertainties and contingencies which are difficult or impossible to predict and are beyond our control. Therefore, such forward-looking statements involve significant risks and uncertainties that could materially affect our expected financial position, financial and operating results, liquidity, cash flows (including, but not limited to, Adjusted Free Cash Flow) and business prospects. 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” in our most recent Annual Report 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 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;
- 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 permitting, 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;
- inflation levels, particularly the recent rise to historically high levels, and government efforts to reduce inflation, including increased interest rates;
- overall domestic and global political and economic trends, geopolitical risks and general economic and industry conditions, such as inflation, rising interest rates, increased volatility in financial and credit markets, global supply chain disruptions and the government interventions into the financial markets and economy;
- risks related to the Macpherson Acquisition, including the risk that we may fail to successfully integrate the assets into our operations, identify risks or liabilities associated with Macpherson Energy, its operations or assets, or realize any anticipated benefits or growth;
- the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict in oil and gas producing regions, including the ongoing conflict in Ukraine, the recent Israel-Hamas conflict, or a prolonged recession, among other factors;

- volatility of oil, natural gas and NGL prices, including as a result of political instability, armed conflict or economic sanctions;
- 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, including due to the actions of foreign producers, importantly including OPEC+ and change in OPEC+'s production levels;
- 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;
- 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 or acquisitions;
- drilling and production results, 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, floods, and epidemics or pandemics, including the effects of related public health concerns and the impact of actions that may be taken by governmental authorities and other third parties in response to a pandemic;
- 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 cyberattacks; and.
- governmental actions and political conditions, as well as actions by other third parties that are beyond our control.

Any forward-looking statement speaks only as of the date on which such statement is made. Except as required by law, we undertake no responsibility to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise except as required by applicable law.

All forward-looking statements, expressed or implied, included in this Quarterly Report 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, 2023, 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 2022 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 decline.

We have historically hedged a large portion of our expected crude oil and our natural gas production, as well as our natural gas purchase requirements to reduce exposure to fluctuations in commodity prices. We use derivatives such as swaps, calls, puts and collars 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, 2023, the fair value of our hedge positions was a net liability of approximately $72 million. A 10% increase in the oil and natural gas index prices above the September 30, 2023 prices would result in a net liability of approximately $167 million; conversely, a 10% decrease in the oil and natural gas index prices below the September 30, 2023 prices would result in a net asset of approximately $9 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 Chief Executive Officer and our Vice President, Chief Financial Officer and Chief Accounting 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 Exchange Act) 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, 2023.

The Company’s disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. The Company’s disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company’s management, including the Chief Executive Officer and the Vice President, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in the Company’s internal control over financial reporting during the third quarter of 2023 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 “Securities Class Action”) 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 (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933 (as amended, the “Securities Act”), and Sections 10(b) and 20(a) of the Exchange Act of 1934 (as amended, the “Exchange Act”), on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company’s 2018 IPO; or (ii) Berry Corp.’s securities between July 26, 2018 and November 3, 2020 (the “Class Period”). In particular, 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 November 3, 2020.

On November 1, 2021, the court-appointed 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 and Sections 10(b) and 20(a) of the Exchange Act, 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 filed a motion to dismiss on January 24, 2022 and on September 13, 2022, the court issued an order denying that motion, and the case moved into discovery. On February 13, 2023, the plaintiffs filed a motion for class certification, and on April 14, 2023, the defendants filed their opposition; the plaintiffs filed their reply on May 26, 2023, and a hearing on the motion for class certification was set for August 23, 2023.

On July 31, 2023, the parties executed a Memorandum of Understanding memorializing an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. On September 18, 2023, the plaintiffs and Defendants executed a Stipulation and Agreement of Settlement, and the plaintiffs filed a motion seeking preliminary approval of the settlement. On October 18, 2023, the Court granted that motion, issuing a preliminary approval order and scheduling a final settlement approval hearing for February 6, 2024. The parties will now move forward with the notice and approval process, which is expected to include, among other things, the February 6, 2024 final approval hearing, an opt-out process, and opportunities for class members to object to the settlement. The Defendants continue to maintain that the claims are without merit and admit no liability in connection with the settlement.

On October 20, 2022, a shareholder derivative lawsuit (the “Assad Lawsuit”) was filed in the United States District Court for the Northern District of Texas by putative stockholder George Assad, allegedly on behalf of the Company, that piggy-backs on the Securities Class Action and which is currently pending before the same court. The derivative complaint names certain current and former officers and directors as defendants, and generally alleges that they breached their fiduciary duties by causing or failing to prevent the securities violations alleged in the securities class action. The derivative complaint also alleges claims for unjust enrichment as against all defendants, and claims for contribution and indemnification under Sections 10(b) and 21D of the Exchange Act. On January 27, 2023, the court granted the parties’ joint stipulated request to stay the Assad Lawsuit pending resolution of the Securities Class Action.

On January 20, 2023, a second shareholder derivative lawsuit (the “Karp Lawsuit,” together with the Assad Lawsuit, the “Shareholder Derivative Actions”) was filed, this time in the United States District Court for the District of Delaware, by putative stockholder Molly Karp, allegedly on behalf of the Company, again piggy-backing on the Securities Class Action. This complaint, similar to the Assad Lawsuit, is brought against certain current and former officers and directors of the Company, asserting breach of fiduciary duty, aiding and abetting, and contribution claims based on the defendants allegedly having caused or failed to prevent the securities violations alleged in the securities class action. In addition, the complaint asserts a claim under Section 14(a) of the Exchange Act, alleging that Berry’s 2022 proxy statement was false and misleading in that it suggested the Company’s internal controls were sufficient and the Board of Directors was adequately overseeing material risks facing the Company when, according to the derivative plaintiff, that was not the case. On February 13, 2023, the court granted the parties’ joint stipulated request to stay the Karp Lawsuit pending resolution of a motion for summary judgment by the defendants in the Securities Class Action. The proposed settlement of the Securities Class Action does not relate to the Shareholder Derivative Actions. The defendants continue to believe the claims in the Shareholder Derivative Actions are without merit and intend to defend vigorously against them, but there can be no assurances as to the outcome. At this time, we are unable to estimate the probability or the amount of liability, if any, related to these matters.

In addition, on or around April 17, 2023, the Company received a stockholder litigation demand that the Board of Directors investigate and commence legal proceedings against certain current and former officers and directors based ostensibly on the same claims asserted in the Shareholder Derivative Actions. The Board of Directors appointed a Demand Review Committee for the purpose of reviewing the demand.

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, 2022 included in the Annual Report.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. A discussion of such risks and uncertainties may be found under the heading “Item 1A. Risk Factors” in our most recent Annual Report and “Item 1A. Risk Factors” in our Quarterly Report for the three months ended June 30, 2023.

Recent action by the state of California imposing additional financial assurance requirements related to plugging and abandonment costs, decommissioning, and site restoration on those who acquire the right to operate wells and production facilities could impact our ability to sell or acquire assets in the state of California or increase our costs in connection with the same.

On October 7, 2023, the California Governor signed into law Assembly Bill 1167 (AB 1167), which imposes more stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in the state of California, requiring them to file a bond in an amount determined by the state to sufficiently cover plugging and abandonment costs, decommissioning, and site restoration. AB 1167 prohibits the transfer of operatorship of a well or production facility until a determination on the appropriate bond amount has been completed by the state and the bond has been filed. We are still assessing the impact of AB 1167. In addition, although AB 1167 has been signed into law, Governor Newsom has called for further legislative changes to these new requirements to mitigate against the potential risk of the implementation of AB 1167 ultimately increasing the number of orphaned wells becoming state liabilities in California. However, we cannot predict what form these changes may ultimately take or if the legislature will act on the Governor’s request. Implementation of this law may lead to the delay or additional costs with respect to acquisitions or dispositions, which could impact our ability to grow or explore new strategic areas - or exit others - within the state of California.

The Climate Corporate Data Accountability Act and Climate-Related Financial Risk Act both impose climate-related reporting obligations including greenhouse gas emissions which could result in additional costs for compliance, restrictions on our access to capital, and increased litigation and reputational risk.

Governor Newsom signed the Climate Corporate Data Accountability Act (“CCDAA”), or Senate Bill 253 (SB 253), into law on October 7, 2023, alongside the Climate-Related Financial Risk Act (“CRFRA”), or Senate Bill 261 (SB 261). The CCDAA requires both public and private U.S. companies that are “doing business in California” and that have a total annual revenue of $1 billion to publicly disclose and verify, on an annual basis, Scope 1, 2 and 3 GHG emissions. The CRFRA requires the disclosure of a climate-related financial risk report (in line with the Task Force on the Climate-related Financial Disclosures recommendations or equivalent disclosure requirements under the International Sustainability Standards Board’s climate-related disclosure standards) every other year for public and private companies that are “doing business in California” and have total annual revenue of $500 million. Reporting under both laws would begin in 2026, though the Governor of California has directed further consideration of the implementation deadlines for each of the laws. Currently, we are still assessing the potential impacts of these laws; however, implementation may result in additional costs to comply with these disclosure requirements as well as increased costs of and restrictions on access to capital if our disclosures are not perceived as meeting applicable third-party verification of GHG emissions and climate-related criteria. Separately, enhanced climate-related disclosure requirements could lead to reputational or other harm to our relationships with customers, regulators, investors or other stakeholders. In addition, we may also face increased litigation risks arising from enhanced climate-related disclosure requirements relating to alleged damages resulting from GHG emissions from our operations, statements alleged to have been made by us or others in our industry regarding climate change risks, or in connection with any future disclosures we may make regarding reported emissions, particularly given the inherent complexity of multiple, overlapping GHG reporting regulations with respect to calculating and reporting GHG emissions.

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

Stock Repurchase Program

The Company did not repurchase any shares during the three months ended September 30, 2023. For the nine months ended September 30, 2023, we repurchased 1.4 million shares (all in the second quarter) for approximately $10 million. As of September 30, 2023, the Company had repurchased a total of 11,949,247 shares under the stock repurchase program for approximately $114 million in aggregate, which is 16% of outstanding shares. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company intends to allocate a portion of Adjusted Free Cash Flow to opportunistic share repurchases.

In February 2023, the Board of Directors approved an increase of $102 million to the Company’s stock repurchase authorization bringing the Company’s remaining share authority to $200 million. As of September 30, 2023, the Company’s remaining total share repurchase authority is $190 million. The Board’s authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions, subject to market conditions and other factors, up to the aggregate amount authorized by the Board. The Board’s authorization has no expiration date.

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. Purchases may be commenced or suspended at any time without notice and do not obligate the company to purchase shares during any period or at all. Any shares repurchased are reflected as treasury stock and any shares acquired will be available for general corporate purposes.

Item 5. Other Information

(c) Trading Plans

During the three months ended September 30, 2023, no director or officer of the Company adopted or terminated a “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as each term is defined in Item 408(a) of Regulation S-K.

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	Fourth Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.1 of Form 8-K filed January 31, 2023)
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)
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:

"*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 unusual and infrequent items.

"*Adjusted Free Cash Flow*" which is defined as cash flow from operations less regular fixed dividends and maintenance capital.

"*Adjusted General and Administrative Expenses*" is a non-GAAP financial measure defined as general and administrative expenses adjusted for non-cash stock compensation expense and 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, unusual and infrequent items, and the income tax expense or benefit of these adjustments using our effective tax rate.

"AROs" means asset retirement obligations.

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

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

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

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

"*boe*" means barrel of oil equivalent, determined using the ratio of one bbl of oil, condensate or natural gas liquids to six mcf of natural gas.

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

"*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.

"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.

"CEQA" is an abbreviation for the California Environmental Quality Act which, among other things, requires certain governmental agencies to conduct environmental review of projects for which the agency is issuing a permit.

"CJWS" refers to C&J Well Services, LLC and CJ Berry Well Services Management, LLC, the two entities that constitute our upstream well servicing and abandonment business segment in California.

"*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.

"*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.

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

"*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.

"HSE" is an abbreviation for Health, Safety, and Environmental.

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

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

"*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.

"*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.

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

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

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

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

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

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

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

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

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

"*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.

"*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.

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

"mb*bl/d*" means mbbl per day.

"mboe" means one thousand barrels of oil equivalent.

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

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

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

"mmboe" means one million barrels of oil equivalent.

"mmb*tu*" means one million btus.

"mmb*tu/d*" means mmbtu per day.

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

"mm*cf/d*" means mmcf per day.

"*MW*" means megawatt.

"*MWHs*" means megawatt hours.

"*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.

"*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.

"*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

"*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.

"*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.

"*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.

"*SOFR*" is an abbreviation for Secured Overnight Financing Rate.

"*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.

"*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 CERCLA.

"*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 1, 2023	*/s/* Fernando Araujo
		Fernando Araujo Chief Executive Officer (Principal Executive Officer)
Date:	November 1, 2023	*/s/* M. S. Helm
		Michael S. Helm Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial Officer and 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, Fernando Araujo, 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 1, 2023

/s/ Fernando Araujo

Fernando Araujo
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, Michael S. Helm, 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 1, 2023

/s/ M.S. Helm

Michael S. Helm

Vice President, Chief Financial Officer, and Chief Accounting 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, 2023, as filed with the Securities and Exchange Commission on November 1, 2023 (the "Report"), Fernando Araujo, as Chief Executive Officer of the Company, and Michael S. Helm, as Vice President, Chief Financial Officer, and Chief Accounting 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 1, 2023	/s/ Fernando Araujo
		Fernando Araujo
		Chief Executive Officer

Date:	November 1, 2023	/s/ M.S. Helm
		Michael S. Helm
		Vice President, Chief Financial Officer and Chief Accounting 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.