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 June 30, 2024
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 August 6, 2024 76,938,994

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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

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

	June 30, 2024	December 31, 2023
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,688	$ 4,835
Accounts receivable, net of allowance for doubtful accounts of $655 at June 30, 2024 and December 31, 2023	82,017	86,918
Derivative instruments	—	5,288
Other current assets	38,784	43,759
Total current assets	127,489	140,800
Noncurrent assets:		
Oil and natural gas properties	1,925,855	1,906,134
Accumulated depletion and amortization	(663,214)	(592,621)
Total oil and natural gas properties, net	1,262,641	1,313,513
Other property and equipment	170,285	167,767
Accumulated depreciation	(83,333)	(74,668)
Total other property and equipment, net	86,952	93,099
Deferred income taxes	45,915	30,308
Derivative instruments	—	5,463
Other noncurrent assets	9,912	10,975
Total assets	$ 1,532,909	$ 1,594,158
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 168,426	$ 213,401
Derivative instruments	36,119	9,781
Total current liabilities	204,545	223,182
Noncurrent liabilities:		
Long-term debt	433,656	427,993
Derivative instruments	19,827	959
Deferred income taxes	—	2,344
Asset retirement obligations	178,980	176,578
Other noncurrent liabilities	22,941	5,126
Commitments and Contingencies - Note 4		
Stockholders' equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 88,942,805 and 87,671,241 shares issued; and 76,938,994 and 75,667,430 shares outstanding, at June 30, 2024 and December 31, 2023, respectively)	89	88
Additional paid-in-capital	782,993	819,157
Treasury stock, at cost (12,003,811 shares at June 30, 2024 and December 31, 2023, respectively)	(113,768)	(113,768)
Retained earnings	3,646	52,499
Total stockholders' equity	672,960	757,976
Total liabilities and stockholders' equity	$ 1,532,909	$ 1,594,158

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 June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 168,781	$ 157,703	$ 335,099	$ 324,060
Services revenue	31,155	47,674	62,838	92,297
Electricity sales	3,691	3,078	7,934	8,523
(Losses) gains on oil and gas sales derivatives	(5,844)	20,871	(77,044)	59,370
Other revenues	36	36	103	81
Total revenues and other	197,819	229,362	328,930	484,331
Expenses and other:				
Lease operating expenses	53,989	54,707	114,686	189,542
Costs of services	25,021	37,083	52,325	73,182
Electricity generation expenses	552	1,273	1,645	3,773
Transportation expenses	1,039	1,096	2,098	2,137
Acquisition costs	1,394	972	4,011	972
General and administrative expenses	18,881	22,488	39,115	54,157
Depreciation, depletion, and amortization	42,843	39,755	85,674	79,876
Impairment of oil and gas properties	43,980	—	43,980	—
Taxes, other than income taxes	12,674	13,707	28,363	24,167
Losses on natural gas purchase derivatives	2,642	14,024	7,123	13,414
Other operating (income)	(3,204)	(1,033)	(3,337)	(1,319)
Total expenses and other	199,811	184,072	375,683	439,901
Other expenses:				
Interest expense	(10,050)	(8,794)	(19,190)	(16,631)
Other, net	(53)	(110)	(136)	(185)
Total other expenses	(10,103)	(8,904)	(19,326)	(16,816)
(Loss) income before income taxes	(12,095)	36,386	(66,079)	27,614
Income tax (benefit) expense	(3,326)	10,616	(17,226)	7,703
Net (loss) income	$ (8,769)	$ 25,770	$ (48,853)	$ 19,911
Net (loss) income per share:				
Basic	$ (0.11)	$ 0.34	$ (0.64)	$ 0.26
Diluted	$ (0.11)	$ 0.33	$ (0.64)	$ 0.25

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

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

	Six-Month Period Ended June 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

	Six-Month Period Ended June 30, 2024				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	(in thousands)				
December 31, 2023	$ 88	$ 819,157	$ (113,768)	$ 52,499	$ 757,976
Shares withheld for payment of taxes on equity awards and other	—	(5,257)	—	—	(5,257)
Stock-based compensation	—	616	—	—	616
Issuance of common stock	1	—	—	—	1
Dividends declared on common stock, $0.26/share	—	(24,408)	—	—	(24,408)
Net loss	—	—	—	(40,084)	(40,084)
March 31, 2024	89	790,108	(113,768)	12,415	688,844
Stock-based compensation	—	2,118	—	—	2,118
Dividends declared on common stock, $0.12/share	—	(9,233)	—	—	(9,233)
Net loss	—	—	—	(8,769)	(8,769)
June 30, 2024	$ 89	$ 782,993	$ (113,768)	$ 3,646	$ 672,960

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

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

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(in thousands)	
Cash flows from operating activities:		
Net (loss) income	$ (48,853)	$ 19,911
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	85,674	79,876
Amortization of debt issuance costs	1,393	1,288
Impairment of oil and gas properties	43,980	—
Stock-based compensation expense	2,375	8,318
Deferred income taxes	(17,951)	7,033
Other operating expenses	44	793
Derivative activities:		
Total losses (gains)	84,167	(45,956)
Cash settlements (paid) received on derivatives	(28,209)	34,943
Changes in assets and liabilities:		
Decrease in accounts receivable	4,927	17,179
Decrease in other assets	5,849	244
(Decrease) in accounts payable and accrued expenses	(47,898)	(56,722)
Increase (decrease) in other liabilities	12,666	(2,588)
Net cash provided by operating activities	98,164	64,319
Cash flows from investing activities:		
Capital expenditures:		
Capital expenditures	(59,261)	(42,528)
Changes in capital expenditures accruals	4,147	(8,564)
Acquisitions, net of cash received	(6,033)	(7,329)
Net cash used in investing activities	(61,147)	(58,421)
Cash flows from financing activities:		
Borrowings under 2021 RBL credit facility	342,500	200,000
Repayments on 2021 RBL credit facility	(337,500)	(175,000)
Dividends paid on common stock	(33,640)	(51,681)
Purchase of treasury stock	—	(10,029)
Shares withheld for payment of taxes on equity awards and other	(5,257)	(6,872)
Debt issuance cost	(1,267)	—
Net cash used in financing activities	(35,164)	(43,582)
Net increase (decrease) in cash and cash equivalents	1,853	(37,684)
Cash and cash equivalents:		
Beginning	4,835	46,250
Ending	$ 6,688	$ 8,566

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 Delaware limited liability company subsidiaries: (1) Berry Petroleum Company, LLC ("Berry LLC"), which owns Macpherson Energy, LLC ("Macpherson Energy") and its subsidiaries; (2) CJ Berry Well Services Management, LLC ("C&J Management") and (3) C&J Well Services, LLC, ("C&J," together with C&J Management, "CJWS"). As the context may require, the "Company," "we," "our" or similar words in this report refer to, Berry Corp., together with its subsidiaries, Berry LLC, C&J Management, and C&J.

Nature of Business

We are a western United States independent upstream energy company with a focus on onshore, low geologic risk, low decline, 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 Utah, are characterized by high oil content and are predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Utah assets are in the Uinta basin (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 E&P 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, 2023.

New Accounting Standards Issued, But Not Yet Adopted

In November 2023, the Financial Accounting Standards Board ("FASB") issued guidance to improve the reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. In addition, the guidance enhances interim disclosure requirements, clarifies circumstances in which an entity can disclose multiple segment measures of profit or loss and contains other disclosure requirements. The purpose of the guidance is to enable investors to better understand an entity's overall performance and assess potential future cash flows. The guidance is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. We are currently evaluating the impact the new guidance will have on our consolidated financial statements.

In December 2023, the FASB issued rules to enhance the annual income tax disclosure to address investors' request for more information regarding tax risks and opportunities present in an entity's operations related to the effective tax rate reconciliation and income taxes paid. The guidance is effective for fiscal periods beginning after December 15, 2024, with early adoption permitted for annual financial statements. We are currently evaluating the impact the new guidance will have on our consolidated financial statements.

Note 2—Debt

The following table summarizes our outstanding debt:

	June 30, 2024	December 31, 2023	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ 36,000	$ 31,000	variable rates 10.50% (2024) and 10.50% (2023)	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% (2024) and 9.75% (2023)	June 5, 2027	CJWS property and certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	436,000	431,000			
Less: Debt Issuance Costs	(2,344)	(3,007)			
Long-Term Debt, net	$ 433,656	$ 427,993			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At June 30, 2024 and December 31, 2023, debt issuance costs reported in "other noncurrent assets" on the balance sheet were approximately (i) $2 million and $3 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 an issuing bank, and each of the lenders from time to time party 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 June 30, 2024 and December 31, 2023, debt issuance costs, net of amortization, for the unsecured notes due February 2026 (the "2026 Notes") reported in "Long-Term Debt, net" on the balance sheet were approximately $2 million and $3 million, respectively.

For each of the three and six month periods ended June 30, 2024 and 2023, the amortization expense for the 2021 RBL Facility, the 2022 ABL Facility and the 2026 Notes, combined, was approximately $1 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 $395 million and $391 million at June 30, 2024 and December 31, 2023, respectively. The 2026 Notes are Level 1 in the fair value hierarchy.

2021 RBL Facility

The 2021 RBL Facility provides for a revolving loan with up to $500 million of commitment, subject to a borrowing base and an aggregate elected commitment amount. 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.

As of June 30, 2024, the 2021 RBL Facility had a $500 million revolving commitment, a $200 million borrowing base, a $200 million aggregate elected commitment amount 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 commitment amount 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 terms of the 2021 RBL Facility. The 2021 RBL Facility is available to us for general corporate purposes, including working capital.

If we are not able to extend the maturity date of the 2021 RBL Facility, the 2021 RBL Facility will be classified as current debt as of August 26, 2024. The failure to repay the 2021 RBL Facility promptly following any such reclassification to current debt could result in a going concern qualification with respect to our annual audited financial statements. We may not be successful in refinancing, repaying or extending the maturity of our 2026 Notes or our 2021 RBL Facility, and any such refinancing may not be obtainable on terms favorable to us. If we are not able to refinance the 2026 Notes or extend the maturity date of the 2021 RBL Facility, the 2021 RBL Facility and the 2026 Notes will be classified as current debt as of August 26, 2024 and February 15, 2025, respectively.

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 on base rate borrowings is payable quarterly in arrears 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 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 provides that, to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. In addition, 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 June 30, 2024, we were in compliance with all of covenants under the 2021 RBL Facility.

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.

The 2021 RBL Facility is guaranteed by Berry Corp. and certain of its subsidiaries. Each future subsidiary of Berry Corp., with certain exceptions, is required to guarantee our obligations and obligations of the other guarantors under the 2021 RBL Facility and under certain hedging transactions and banking services arrangements. The lenders under the 2021 RBL Facility hold a mortgage on at least 90% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions. C&J and C&J Management do not guarantee the Revolving Credit Facility or grant any liens on their assets to secure any obligations under the 2021 RBL Facility.

On July 30, 2024, we entered into a letter agreement to amend the 2021 RBL Facility to extend the permitted tenor of certain commodity hedging agreements which we may enter into, from a tenor not to exceed 48 months to a tenor not to exceed 60 months.

As of June 30, 2024, we had $36 million borrowings outstanding, $9 million in letters of credit outstanding and approximately $155 million of available borrowing capacity under the 2021 RBL Facility. As of July 31, 2024, we reduced our borrowings outstanding under the 2021 RBL Facility to $28 million.

2022 ABL Facility

Subject to satisfaction of customary conditions precedent to borrowing, as of June 30, 2024, C&J and C&J Management could borrow up to the lesser of (x) $10 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 June 30, 2024, the borrowing base was $10 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 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”. Interest is due quarterly, in arrears. In June 2024, we entered into the Third Amendment to Revolving Loan and Security Agreement and Amendment to Other Loan Documents which, among other things, extended the maturity of the 2022 ABL Facility from June 5, 2025 to June 5, 2027, unless terminated earlier in accordance with the terms of the 2022 ABL Facility.

The 2022 ABL Facility requires C&J and C&J Management 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 June 30, 2024, each of C&J and C&J Management was in compliance with all of the covenants under the 2022 ABL Facility.

The 2022 ABL Facility also contains other customary affirmative and negative covenants, as well as events of default and remedies. If C&J or C&J Management 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. The obligations of C&J and C&J Management under the 2022 ABL Facility are guaranteed by C&J Management and C&J, respectively, and are secured by liens on substantially all of the personal property of C&J and C&J Management, subject to customary exceptions. The obligations of C&J and C&J Management 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.

As of June 30, 2024, each of C&J and C&J Management had no borrowings and $3 million letters of credit outstanding with $7 million of available borrowing capacity under the 2022 ABL Facility.

Senior Unsecured Notes Due February 2026

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 and certain of its subsidiaries. C&J and C&J Management do not guarantee the 2026 Notes.

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 June 30, 2024.

If we are not able to refinance the 2026 Notes, the 2026 Notes will be classified as current debt as of February 15, 2025. The failure to repay the 2026 Notes promptly following any such reclassification to current debt could result in a going concern qualification with respect to our annual audited financial statements. We may not be successful in refinancing, repaying or extending the maturity of our 2026 Notes or our 2021 RBL Facility, and any such refinancing may not be obtainable on terms favorable to us. If we are not able to refinance the 2026 Notes or extend the maturity date of the 2021 RBL Facility, the 2021 RBL Facility and the 2026 Notes will be classified as current debt as of August 26, 2024 and February 15, 2025, respectively.

Debt Repurchase Program

In February 2020, the board of directors (the “Board of Directors”) adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and do not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any 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, which specifies the volume and types of our hedges, 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 generally 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 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.

Oil Sales Hedges

For fixed-price 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.

Gas Purchase Hedges

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

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 June 30, 2024, we have net payable deferred premiums of approximately $1 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 June 30, 2024, we had the following crude oil production and gas purchases hedges.

	Q3 2024	Q4 2024	FY 2025	FY 2026	FY 2027
Brent - Crude Oil production					
Swaps					
Hedged volume (bbls)	1,481,749	1,438,656	4,859,125	2,312,268	722,000
Weighted-average price ($/bbl)	$ 76.88	$ 76.93	$ 76.08	$ 71.61	$ 71.48
Sold Calls[(1)]					
Hedged volume (bbls)	92,000	92,000	296,127	1,251,500	318,500
Weighted-average price ($/bbl)	$ 105.00	$ 105.00	$ 88.69	$ 85.53	$ 80.03
Purchased Puts (net)[(2)]					
Hedged volume (bbls)	322,000	322,000	—	—	—
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ —	$ —	$ —
Purchased Puts (net)[(2)]					
Hedged volume (bbls)	—	—	296,127	1,251,500	318,500
Weighted-average price ($/bbl)	$ —	$ —	$ 60.00	$ 60.00	$ 65.00
Sold Puts (net)[(2)]					
Hedged volume (bbls)	46,000	46,000	—	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ —	$ —	$ —
NWPL - Natural Gas purchases[(3)]					
Swaps					
Hedged volume (mmbtu)	3,680,000	3,680,000	13,380,000	3,040,000	—
Weighted-average price ($/mmbtu)	$ 3.96	$ 3.96	$ 4.27	$ 4.26	$ —

(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.
(3) The term "NWPL" is defined as Northwest Rocky Mountain Pipeline.

In addition to the table above, in July and August 2024, we added the following sold oil swaps (Brent) for each of the following years: approximately 250 bbl/d at $75.35 for 2025, approximately 900 bbl/d at $72.86 for 2026, approximately 6,400 bbl/d at $70.40 for 2027, approximately 6,500 bbl/d at $68.36 for 2028, and approximately 2,000 bbl/d at $67.44 for 2029.

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 June 30, 2024 and December 31, 2023:

	June 30, 2024			
	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	$ 10,680	$ (10,680)	$ —
Commodity Contracts	Non-current assets	10,717	(10,717)	—
Liabilities:				
Commodity Contracts	Current liabilities	(46,799)	10,680	(36,119)
Commodity Contracts	Non-current liabilities	(30,544)	10,717	(19,827)
Total derivatives		$ (55,946)	$ —	$ (55,946)

	December 31, 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	$ 26,230	$ (20,942)	$ 5,288
Commodity Contracts	Non-current assets	28,992	(23,529)	5,463
Liabilities:				
Commodity Contracts	Current liabilities	(30,723)	20,942	(9,781)
Commodity Contracts	Non-current liabilities	(24,488)	23,529	(959)
Total derivatives		$ 11	$ —	$ 11

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, 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.

(Losses) Gains on Derivatives

	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(in thousands)			
Realized (losses) gains on commodity derivatives:				
Realized (losses) on oil sales derivatives	$ (9,801)	$ (1,770)	$ (14,483)	$ (9,208)
Realized (losses) gains on natural gas purchase derivatives	(9,314)	(10,754)	(13,726)	44,151
Total realized (losses) gains on derivatives	$ (19,115)	$ (12,524)	$ (28,209)	$ 34,943
Unrealized gains (losses) on commodity derivatives:				
Unrealized gains (losses) on oil sales derivatives	$ 3,957	$ 22,641	$ (62,561)	$ 68,578
Unrealized gains (losses) on natural gas purchase derivatives	6,672	(3,270)	6,603	(57,565)
Total unrealized gains (losses) on derivatives	$ 10,629	$ 19,371	$ (55,958)	$ 11,013
Total (losses) gains on derivatives	$ (8,486)	$ 6,847	$ (84,167)	$ 45,956

Note 4—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, false claims, 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 June 30, 2024 and December 31, 2023. 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 June 30, 2024, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matters

In November 2020, a putative securities class action (the “Securities Class Action”) was filed in the United States District Court for the Northern District of Texas, claiming that Berry Corp. and certain of its current and former directors and officers violated the Securities Act of 1933 and the Exchange Act of 1934 by allegedly making false and misleading statements between the IPO and November 3, 2020, and in the IPO offering materials, about the Company’s permits and permitting processes.

While the motion for class certification was still pending before the court, the parties reached an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. Following notice to the class and an opt-out and objection process, the Court granted final approval of the settlement on February 6, 2024, and terminated the case. The Defendants continue to maintain that the claims were without merit and admitted no liability in connection with the settlement.

While the Securities Class Action is now concluded, certain related shareholder derivative actions remain pending. 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 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 further developments in the Securities Class Action.

The settlement of the Securities Class Action did not resolve the Shareholder Derivative Actions, which remain pending. 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.

Commitments

We have entered into contracts to purchase GHG compliance instruments totaling $22 million, of which $7 million will be delivered and paid in the fourth quarter 2024 and the remaining $15 million of these instruments will be delivered and paid in 2025.

Note 5—Equity

Cash Dividends

In the first quarter of 2024, our Board of Directors declared a fixed cash dividend of $0.12 per share, as well as a variable cash dividend of $0.14 per share which was based on the results of the fourth quarter of 2023, for a total of $0.26 per share, which we paid in March 2024. In April 2024, the Board of Directors approved a fixed cash dividend totaling $0.12 per share, which was paid in May 2024. In July 2024, the Board of Directors approved a fixed cash dividend of $0.12 per share and a variable cash dividend of $0.05 per share, based on the results for the six months ended June 30, 2024, for a total of $0.17 per share, which is expected to be paid in August 2024.

Stock Repurchase Program

The Company did not repurchase any shares during the three and six months ended June 30, 2024. As of June 30, 2024, the Company had repurchased a total of 11.9 million shares, cumulatively, under the stock repurchase program for approximately $114 million in aggregate. According to the shareholder return model, the Company may allocate a portion of Adjusted Free Cash Flow, a non-GAAP measure, to opportunistic share repurchases.

As of June 30, 2024, the Company's remaining total share repurchase authority approved by the Board of Directors was $190 million. The Board of Directors' authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions or by other means, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors. The Board of Directors authorization has no expiration date.

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 the share repurchase program does 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 March 2024, pursuant to the Company's 2022 Omnibus Incentive Plan, the Company granted (i) approximately 1,328,000 restricted stock units ("RSUs"), which will vest annually in equal amounts over three years or, in the case of directors, on March 1, 2025, and (ii) a target number of approximately 406,000 performance-based restricted stock units ("PSUs"), which will cliff vest at the end of a three-year performance period, at the earned performance level. The fair value of these RSU and PSU awards was approximately $13 million.

The RSUs awarded in March 2024 are solely time-based awards. Of the PSUs awarded in March 2024, (a) 50% of such will vest, if at all, at the earned performance level, based on the Company's absolute total stockholder return ("TSR") performance metric, which is defined as the capital gains per share of stock plus cumulative dividends and (b) 50% of such will vest, if at all, at the earned performance level, based on the relative TSR performance metric, which is defined as the capital gains per share of stock plus cumulative dividends, with TSR measured on a relative basis to the TSR of the 47 exploration and production companies in the Vanguard World Fund - Vanguard Energy ETF Index plus the S&P SmallCap 600 Value Index (collectively, the "Peer Group") during the performance period. Depending on the results achieved during the three-year performance period, the actual number of shares that a grant recipient earns at the end of the performance period may range from 0% to 200% of the target number of PSUs granted.

The fair value of the RSUs was determined using the grant date stock price. The grant date fair value of the PSUs was determined using a Monte Carlo simulation to estimate the TSR ranking of the Company for the relative TSR award and the value of the absolute TSR award. The historical volatility was determined at the date of grant for the Company and for each company in the peer group. 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:

	June 30, 2024	December 31, 2023
	(in thousands)	
Prepaid expenses	$ 7,192	$ 12,330
Materials and supplies	18,087	17,021
Deposits	8,342	9,012
Oil inventories	3,931	4,098
Other	1,232	1,298
Total other current assets	$ 38,784	$ 43,759

Noncurrent assets

Other noncurrent assets at June 30, 2024 was approximately $10 million, which mainly included $6 million of operating lease right-of-use assets, net of amortization and $3 million of deferred financing costs, net of amortization. At December 31, 2023, other non-current assets was approximately $11 million, which included $8 million of operating lease right-of-use assets, net of amortization and $3 million of deferred financing costs, net of amortization.

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

	June 30, 2024	December 31, 2023
	(in thousands)	
Accounts payable - trade	$ 19,499	$ 31,184
Deferred acquisition payable[(1)]	20,000	18,999
Accrued expenses	51,533	55,663
Royalties payable	16,897	28,179
Greenhouse gas liability - current portion[(2)]	17,538	37,945
Taxes other than income tax liability	7,902	6,488
Accrued interest	12,599	11,999
Asset retirement obligations - current portion	20,000	20,000
Operating lease liability	2,458	2,944
Total accounts payable and accrued expenses	$ 168,426	$ 213,401

(1) The remaining payable of $20 million, for the acquisition of Macpherson Energy, as of June 30, 2024. The amount was paid in July 2024.

(2) Includes $7 million to be paid in 2024 and the remainder in 2025.

Noncurrent liabilities

The increase of approximately $2 million in the long-term portion of the asset retirement obligations from $177 million at December 31, 2023 to $179 million at June 30, 2024 was due to $6 million of accretion expense and $1 million of liabilities incurred, largely offset by $5 million of liabilities settled during the period.

Other noncurrent liabilities at June 30, 2024 was approximately $23 million, which included approximately $19 million of greenhouse gas liability, and $4 million of operating lease noncurrent liability. At December 31, 2023, other noncurrent liabilities was approximately $5 million, which was operating lease noncurrent liability.

Supplemental Information on the Statement of Operations

For the three and six months ended June 30, 2024, other operating income was $3 million and mainly consisted of prior period royalty receipts and property tax refunds. For the three and six months ended June 30, 2023, other operating income was $1 million, mainly due to 2017 property tax refund.

Supplemental Cash Flow Information

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

	Six Months Ended June 30,	
	2024	2023
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 1,873	$ 552
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 16,651	$ 15,392
Income taxes payments	$ 491	$ 670

Note 7—Acquisition and Divestiture

In April 2024, we purchased a 21% working interest in four, two-to-three mile lateral wellbores that have been drilled and completed and were placed into production in the second quarter of 2024. These are adjacent to our existing operations in Utah, and the results from these wells will be used to evaluate opportunities on our own acreage. The total purchase price was approximately $10 million, subject to customary purchase price adjustments, which was reported as capital expenditures.

During the second quarter of 2024, we purchased additional working interests in our Round Mountain field for approximately $4 million.

In July 2024, we completed the sale of CJWS' storage facility in Ventura, California for approximately $8 million.

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 six months ended June 30, 2024 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 six months ended June 30, 2023, 2,564,000 and 3,156,000 RSU and PSU shares were included in the diluted EPS calculation, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
	(in thousands except per share amounts)			
Basic EPS calculation				
Net (loss) income	$ (8,769)	$ 25,770	$ (48,853)	$ 19,911
Weighted-average shares of common stock outstanding	76,939	76,721	76,597	76,419
Basic (loss) income per share	$ (0.11)	$ 0.34	$ (0.64)	$ 0.26
Diluted EPS calculation				
Net (loss) income	$ (8,769)	$ 25,770	$ (48,853)	$ 19,911
Weighted-average shares of common stock outstanding	76,939	76,721	76,597	76,419
Dilutive effect of potentially dilutive securities(1)	—	2,564	—	3,156
Weighted-average common shares outstanding - diluted	76,939	79,285	76,597	79,575
Diluted (loss) income per share	$ (0.11)	$ 0.33	$ (0.64)	$ 0.25

(1) We excluded approximately 0.2 million and 0.3 million of combined RSUs and PSUs from the dilutive weighted-average common shares outstanding for the three and six months ended June 30, 2024, respectively, 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. Revenue from CJWS is generated from well servicing and abandonment business.

The following table provides disaggregated revenue for the three and six months ended June 30, 2024 and 2023:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
	(in thousands)			
Oil sales	$ 166,466	$ 154,513	$ 329,218	$ 306,647
Natural gas sales	1,440	2,410	4,159	15,953
Natural gas liquids sales	875	780	1,722	1,460
Service revenue(1)	31,155	47,674	62,838	92,297
Electricity sales	3,691	3,078	7,934	8,523
Other revenues	36	36	103	81
Revenues from contracts with customers	203,663	208,491	405,974	424,961
(Losses) gains on oil and gas sales derivatives	(5,844)	20,871	(77,044)	59,370
Total revenues and other	$ 197,819	$ 229,362	$ 328,930	$ 484,331

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $37 million and $49 million and the intercompany elimination was $6 million and $2 million for the three months ended June 30, 2024 and 2023, respectively. Prior to the intercompany elimination, service revenue was approximately $72 million and $96 million and the intercompany elimination was $9 million and $3 million for the six months ended June 30, 2024 and 2023, respectively.

Note 10—Oil and Natural Gas Properties

We evaluate the impairment of our proved and unproved oil and natural gas properties whenever events or changes in circumstance indicate that a property’s carrying value may not be recoverable. If the carrying amount of the proved properties exceeds the estimated undiscounted future cash flows, we record an impairment charge to reduce the carrying values of proved properties to their estimated fair value.

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

An impairment triggering event occurred as a result of the following legislative events. 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, effective January 1, 2023. However, in December 2022, proponents of a voter referendum (the “Referendum”) collected more than the number of signatures required to put SB 1137 on the November 2024 ballot. On February 3, 2023, the Secretary of State of California certified the signatures and confirmed that the Referendum qualified for the November 2024 ballot. SB 1137 was stayed pending a vote of the California General Election in November 2024, however, in June 2024, the ballot proposal was withdrawn with the proposal’s sponsors instead indicating a view to challenging SB 1137 in court and the provisions of SB 1137 are effective immediately. SB 1137 prohibits the issuance of well permits and the construction and operation of new production facilities within a health protection zone of 3,200 feet from a sensitive receptor, as defined in the regulation.

As a result of SB 1137 going to effect immediately in June 2024, we identified a triggering event that required assessment with respect to our proved and unproved oil and gas properties. This event also triggered the reassessment of the DD&A rate of certain proved properties, which was adjusted as of the triggering event date. This legislation went into effect on June 28, 2024, and impacts our ability to develop proved undeveloped reserves and our unproved acreage as planned. Our assessment of the triggering event for proved property impairment did not indicate that after consideration of the impact of SB 1137 it was more likely than not that the associated costs would be recoverable as of the balance sheet date. We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our proved property balance. Our assessment of the triggering event for unproved property cost impairment indicated, however that portions of our capitalized unproved costs would not be recoverable given their proximity to sensitive receptors. Consequently, we recorded a non-cash pre-tax asset impairment charge of $44 million, $33 million after-tax on unproved oil and gas properties in certain California locations during the second quarter of 2024. The impairment represents approximately 2% of our total oil and natural gas properties in the E&P segment.

Note 11—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 Utah. 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 $6 million and $9 million in revenue and expense during consolidation for the three and six months ended June 30, 2024. The intercompany elimination was $2 million and $3 million for the three and six months ended June 30, 2023.

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.

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	Three Months Ended June 30, 2024			
	E&P	**Well Servicing and Abandonment**	**Corporate/Eliminations**	**Consolidated Company**
	(in thousands)			
Revenues[1]	$ 172,508	$ 36,680	$ (5,525)	$ 203,663
Net income (loss) before income taxes	$ 13,860	$ 1,122	$ (27,077)	$ (12,095)
Capital expenditures	$ 41,735	$ 468	$ 122	$ 42,325
Total assets	$ 1,547,334	$ 63,329	$ (77,754)	$ 1,532,909

	Three Months Ended June 30, 2023			
	E&P	**Well Servicing and Abandonment**	**Corporate/Eliminations**	**Consolidated Company**
	(in thousands)			
Revenues[1]	$ 160,817	$ 49,299	$ (1,625)	$ 208,491
Net income (loss) before income taxes	$ 62,012	$ 4,836	$ (30,462)	$ 36,386
Capital expenditures	$ 19,625	$ 1,334	$ 936	$ 21,895
Total assets	$ 1,457,694	$ 72,653	$ (8,644)	$ 1,521,703

	Six Months Ended June 30, 2024			
	E&P	**Well Servicing and Abandonment**	**Corporate/Eliminations**	**Consolidated Company**
	(in thousands)			
Revenues[1]	$ 343,136	$ 72,148	$ (9,310)	$ 405,974
Net (loss) income before income taxes	$ (10,976)	$ (147)	$ (54,956)	$ (66,079)
Capital expenditures	$ 57,152	$ 1,800	$ 309	$ 59,261
Total assets	$ 1,547,334	$ 63,329	$ (77,754)	$ 1,532,909

	Six Months Ended June 30, 2023			
	E&P	**Well Servicing and Abandonment**	**Corporate/Eliminations**	**Consolidated Company**
	(in thousands)			
Revenues[1]	$ 332,664	$ 95,662	$ (3,365)	$ 424,961
Net income (loss) before income taxes	$ 86,182	$ 6,950	$ (65,518)	$ 27,614
Capital expenditures	$ 38,897	$ 2,316	$ 1,315	$ 42,528
Total assets	$ 1,457,694	$ 72,653	$ (8,644)	$ 1,521,703

(1) These revenues do not include hedge settlements.

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 (the "Quarterly Report"), 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, 2023 (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 Corp., together with its subsidiaries, Berry LLC, C&J Management, and C&J.

Our Company

We are a value-driven western United States independent upstream energy company with a focus on onshore, low geologic risk, low decline, 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 Utah, are characterized by high oil content and are predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Utah assets are in the Uinta basin (60% oil and 40% gas). We operate our well servicing and abandonment segment in California.

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 have upstream assets in Utah, located in the Uinta basin, which produce oil and natural gas at depths ranging from 4,000 feet to 8,000 feet. We have high operational control of our existing acreage, which provides significant upside for additional development and recompletions. As of June 30, 2024, we held approximately 99,000 net acres in the Uinta basin. The Uinta basin, which has seen increased activity and consolidation, has been drilled horizontally across the basin and development is moving towards our existing acreage. Our historic Uinta basin development has focused on vertical production from five reservoirs. In April 2024, we purchased a 21% working interest in four, two-to-three mile lateral wells in the Uteland Butte reservoir, which were put on production in the second quarter of 2024. These are adjacent to our existing operations in Utah, and the results from these wells will be used to evaluate opportunities on our own acreage. With a high working interest in our 99,000 acres and the majority of acreage held by production, we are strategically positioned to develop our own acreage horizontally at an optimal pace, staying true to our commitment to generate free cash flow. With the promising initial production rates from the four farm-in horizontal wells, this horizontal well development could be a substantial opportunity, boasting low break-even economics and providing a runway of future development in the increasingly active Uinta basin. We believe that the wells have the potential to unlock all of our Uinta net acres while allowing us to maintain disciplined financial policies.

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.

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 maintain production levels year-over-year and generate free cash flow, which funds our operations, optimizes capital efficiency and maximizes enterprise value. We also strive to maintain an appropriate liquidity position and manageable leverage profile that will enable us to explore attractive organic and strategic growth through commodity price cycles and acquisitions. In addition to operating and developing our existing world-class assets efficiently and strategically under the highest compliance standards, 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 maintaining production levels year-over-year, subject to delays in the issuance of necessary permits and approvals. For more information, see Part I, Items 1 and 2. “Business and Properties—Regulatory Matters—Regulation of the Oil and Gas Industry” in our Annual Report. 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.

Recent Developments

Impairment of Proved Undeveloped Reserves

In June 2024, Senate Bill No. 1137 (SB 1137) became effective, and we identified a triggering event that required assessment with respect to our proved and unproved oil and gas properties. SB 1137 prohibits the issuance of well permits and the construction and operation of new production facilities within a health protection zone of 3,200 feet from a sensitive receptor, as defined in the regulation. This legislation went into effect on June 28, 2024, and impacts our ability to develop proved undeveloped reserves and our unproved acreage as planned. Our assessment of the triggering event for proved property impairment did not indicate that after consideration of the impact of SB 1137 it was more likely than not that the associated costs would be recoverable as of the balance sheet date. Our assessment of the triggering event for unproved property cost impairment did indicate, however that portions of our capitalized unproved costs would not be recoverable given their proximity to sensitive receptors. Consequently, we recorded a non-cash pre-tax asset impairment charge of $44 million, $33 million after-tax on unproved oil and gas properties in certain California locations during the second quarter of 2024. The impairment represents approximately 2% of our total oil and natural gas properties in the E&P segment.

We evaluated our proved properties in accordance with accounting guidance and fair value techniques utilizing the period-end forward price curve, as well as assessing projects. We believe our current plans and exploration and development efforts will allow us to realize the carrying value of our proved property balance.

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; (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 expenditure allocation to maintain production levels year-over-year and determining our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility. 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 “—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.

Adjusted Free Cash Flow

In 2022, we implemented a shareholder return model to determine the allocation of our Adjusted Free Cash Flow. The current allocations of Adjusted Free Cash Flow, last updated at the beginning of 2023, are 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. In addition, we review the allocations under our shareholder return model from time to time based on the same factors. We believe it is likely in future periods that we may have additional restrictions on dividends and share repurchases under any debt agreement we may enter into in connection with refinancing our 2026 Notes (as defined below) or that we will need to reduce such amounts and allocate additional funds to debt repayment. Further, in 2024, we updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, to be cash flow from operations less regular fixed dividends and capital expenditures. This update was to factor in the full capital expenditure requirements of the Company. For 2023, Adjusted Free Cash Flow was defined as cash flow from operations less regular fixed dividends and maintenance capital, which was just the capital expenditures needed to maintain substantially the same volume of annual oil and gas production and was defined as capital expenditures, excluding, when applicable, (i) E&P capital expenditures 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 for prior periods has not been retroactively adjusted for the updated definition. 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.

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 is 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 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 C&J 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, Items 1 and 2. "Business and Properties—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 and natural gas prices have been, and may remain, volatile. As a net gas purchaser, our operating costs are generally expected to be more impacted by the volatility of natural gas prices than our gas sales.

Our well servicing and abandonment business is dependent on expenditures of oil and gas companies, which can in part reflect the volatility of commodity prices, as well as the impact from changes in the regulatory environment. 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.

The price of oil is impacted by the actions of OPEC+ and recently they have implemented production cuts to address global supply levels. In June 2024, OPEC+ extended the reduced production quotas of 3.66 mmbbls/d through the end of 2025 and extended the 2.2 mmbbls/d voluntary cuts through the end of September 2024.

Sanctions and import bans on Russian oil have been implemented by various countries in response to the ongoing conflict in Ukraine, further altering flows of global oil supply. 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 ongoing conflict in the Middle East, international sanctions, speculation as to future actions by OPEC+, higher gas prices, high 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.

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. See Part I, Items 1 and 2. "Business and Properties—Regulatory Matters—"Regulation of Health, Safety and Environmental Matters" in our Annual Report for a description of laws and regulations that affect our business. For more information related to regulatory risks, see Part I, Item 1A. "Risk Factors—Risks Related to Our Operations and Industry" in our Annual Report.

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.

Oil and natural gas prices and differentials may fluctuate significantly as a result of numerous market-related variables. We use derivatives to hedge a portion of our forecasted oil and gas production and gas purchases to reduce our exposure to fluctuations in oil and natural gas prices. The following tables set forth certain average benchmark prices, average realized prices and price realizations as a percentage of average benchmark prices for our products for the periods indicated below.

	Three Months Ended					
	June 30, 2024		March 31, 2024		June 30, 2023	
	Average Price	Realization[1]	Average Price	Realization[1]	Average Price	Realization[1]
Sales of Crude Oil (per bbl):						
Brent	$ 85.03		$ 81.76		$ 77.73	
Realized price without derivative settlements	$ 78.18	92%	$ 75.31	92%	$ 70.68	91%
Effects of derivative settlements	(4.60)		(2.17)		(0.81)	
Realized price with derivative settlements	$ 73.58	87%	$ 73.14	89%	$ 69.87	90%
WTI	$ 80.60		$ 77.02		$ 73.73	
Realized price without derivative settlements	$ 78.18	97%	$ 75.31	98%	$ 70.68	96%
Purchased Natural Gas (per mmbtu)						
Average Monthly Settled Price - NWPL	$ 1.40		$ 3.41		$ 2.85	
Realized price without derivative settlements	$ 2.26	161%	$ 3.99	117%	$ 3.44	121%
Effects of derivative settlements	2.04		0.92		2.20	
Realized price with derivative settlements	$ 4.30	307%	$ 4.91	144%	$ 5.64	198%

	Six Months Ended			
	June 30, 2024		June 30, 2023	
	Average Price	Realization[1]	Average Price	Realization[1]
Sales of Crude Oil (per bbl):				
Brent	$ 83.42		$ 79.96	
Realized price without derivative settlements	$ 76.73	92%	$ 72.62	91%
Effects of derivative settlements	(3.38)		(2.18)	
Realized price with derivative settlements	$ 73.35	88%	$ 70.44	88%
WTI	$ 78.81		$ 74.94	
Realized price without derivative settlements	$ 76.73	97%	$ 72.62	97%
Purchased Natural Gas (per mmbtu)				
Average Monthly Settled Price - NWPL	$ 2.40		$ 12.61	
Realized price without derivative settlements	$ 3.15	131%	$ 11.86	94%
Effects of derivative settlements	1.47		(4.64)	
Realized price with derivative settlements	$ 4.62	193%	$ 7.22	57%

(1) Represents the percentage of our realized prices compared to the indicated index.

Oil Prices

California oil prices are Brent-influenced as California refiners import approximately 75% of the state's demand from OPEC+ countries and other waterborne sources. We believe that receiving Brent-influenced pricing contributes to our ability to continue realizing strong cash margins in California. Though the California market generally receives Brent-influenced pricing, California oil prices are also determined by local supply and demand dynamics, including third-party transportation and infrastructure capacity. In the second quarter of 2024, oil prices increased relative to the first quarter of 2024 and the second quarter of 2023.

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. For the three months ended June 30, 2024, March 31, 2024, and June 30, 2023, Utah had an average realized oil price of $65.58, $65.79 and $61.34, respectively, compared to an average Brent oil price of $85.03, $81.76 and $77.73 for the same periods.

Gas Prices

For our California steam operations, the price we pay for fuel gas purchases is generally based on the Northwest, Rocky Mountains index plus transportation costs 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 $1.47 per mmbtu and as low as $1.29 per mmbtu in the second quarter of 2024. The price from the SoCal Gas city-gate index was as high as $1.96 per mmbtu and as low as $1.72 per mmbtu in the second quarter of 2024. Overall, on an unhedged basis, we paid an average of $2.26 per mmbtu in the second quarter of 2024 for our gas purchases which includes transportation costs. When including the hedging effects in our gas purchases, we paid $4.30, $4.91 and $5.64 per mmbtu in the second quarter of 2024, the first quarter of 2024, and the second quarter of 2023, respectively.

The price of our fuel gas sales is generally based on the Northwest, Rocky Mountains index, as selling at the same index as fuel gas purchases provides a natural hedge for gas purchases. In the second quarter of 2024, our Utah operations had an average realized gas price of $1.78, compared to an average Northwest, Rocky Mountains gas price of $1.40, which was a 127% realization. In the three months ended March 31, 2024 and June 30, 2023, Utah had an average realized gas price of $3.76, and $2.87, compared to an average Northwest, Rocky Mountains gas price of $3.41, or 110% realization, and $2.85, or 101% realization, respectively.

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. We purchase most of our gas in the Rockies and transport 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 2,000 mbbtu/d in the second quarter of 2024, 5,000 mmbtu/d in the first quarter of 2024, and 6,000 mmbtu/d in the second quarter of 2023. 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.

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. Gas prices declined in the second quarter of 2024 compared to the first quarter of 2024. The natural gas futures indicate that prices will rise toward the end of 2024 and into 2025. 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.

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 long-term contracts with terms ending in December 2025 and November 2026. The most significant input and cost of the cogeneration facilities is natural gas.

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.

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. 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 have the effect of reducing the amount of oil and natural gas that we can produce from our wells, potentially reducing such production below levels that would otherwise be possible or economical. Additionally, the regulatory burden in the past has resulted, and in the future could result, in increased costs and consequently has had an adverse effect on operations, capital expenditures, earnings and our competitive position and may continue to have such effects in the future. Violations and liabilities with respect to these laws and regulations could also result in reputational damage and 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, and current political and social trends in California continue to increase limitations on and impose additional permitting, mitigation, and emissions control obligations, amongst others, upon the oil and gas industry. We cannot predict what new laws or regulations California (or the federal government) 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.

Permitting

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, as well as a more time and cost-intensive permitting process. 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. The requirement to demonstrate compliance with CEQA and/or NEPA is currently resulting in (and in the future may result in) significant delays in the issuance of permits to drill new wells, as well as the potential imposition of mitigation measures and 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 the reviewing state and local agencies to 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 Kern County EIR was legally challenged in 2020 and the use of the Kern County EIR is currently stayed and has been stayed through most of the litigation. On March 7, 2024, the California appellate court delivered an opinion finding certain deficiencies in the EIR and enjoining reliance on the Kern County EIR in connection with the issuance of oil and natural gas permit approvals until such deficiencies are remedied. Accordingly, our ability to rely on the Kern County EIR to demonstrate CEQA compliance to obtain permits and approvals to drill new wells is constrained unless and until Kern County is able to favorably resolve the litigation and certify a new revised EIR in compliance with CEQA. As a result of the litigation, since December 2022, neither we nor any other operator have been able to use the Kern County EIR to demonstrate CEQA compliance as required to receive permits to drill new wells. 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 Kern County 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. We began to experience delays in the issuance of new drill permits in those areas during the third quarter of 2023 due to changes in CalGEM's CEQA review process, but we did receive a number of new drill permits in one such area in May 2024. Additionally, in the third quarter of 2023, we started to experience delays in the approval process for sidetrack and workover permits. We believe such delays are also due to changes in CalGEM's CEQA review process. Since that time, CalGEM has provided continued assurances that it is reviewing sidetrack and workover applications and working to finalize its approach to CEQA compliance with respect to such permit review that would allow the agency to ultimately return to regularly issuing these permits on a more predictable timeline. Nevertheless, CalGEM has only approved a relatively low number of sidetrack permits since November 2023 and we also continue to experience some delays in the approval process for workover permits. Despite this, we currently have sufficient permits in hand that should allow us to maintain planned sidetrack drilling activity and conduct workover activity throughout the year. However, it is possible that such permit approval delays could continue and could impede sidetrack drilling and/or workover programs in 2025 and beyond. We are currently exploring a number of alternative permitting strategies to meet future needs; however, we cannot guarantee that any of these strategies will ultimately be successful, and the inability to secure permits (on a timely basis or at all) could adversely impact our business and results of operations. See Part I, Item 1 and 2. "Business and Properties—Regulatory Matters—Regulation of the Oil and Gas Industry" in our Annual Report, as well as Part I, Item 1A. "Risk Factors" in our Annual Report for more information regarding the EIR and other permitting considerations.

Approximately 95% of our production in 2023 came from our base production, with the remainder from 33 wells drilled in California during the year (5 new wells and 28 sidetracks), workovers and other activities related to existing wellbores, and production acquired from the Macpherson Acquisition. Similar to 2023, our 2024 plans focus on drilling sidetracks and working over existing wells. Additionally, our 2024 capital program includes the drilling of one or more of the new wells approved by CalGEM in May 2024 where compliance with CEQA was demonstrated through a non-Kern County EIR environment impact analysis. We believe we will also benefit from production from the assets acquired in the Macpherson Acquisition and other bolt-on acquisitions at the end of 2023 and to date in 2024, as well as production from the Utah Horizontal farm-in well interests, all of which should help maintain consistent production levels from 2023 to 2024. We have in hand all the permits needed to support our 2024 plans, and we are also working to obtain additional permits to support future plans.

Setbacks – SB 1137

Separately, on September 16, 2022, the California Governor signed into law 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. However, in December 2022, proponents of a voter referendum (the "Referendum") collected more than the number of signatures required to put SB 1137 on the November 2024 ballot. On February 3, 2023, the Secretary of State of California certified the signatures and confirmed that the Referendum qualified for the November 2024 ballot. SB 1137 was stayed pending a vote of the

California General Election in November 2024, however, in June 2024, the ballot proposal was withdrawn with the proposal's sponsors instead indicating a view to challenging SB 1137 in court. The provisions of SB 1137 are effective immediately in June 2024.

Certain of our undeveloped costs are located within the setbacks established by SB 1137, which required an analysis of impairment as of the date the law became effective. Due to the June 28, 2024 implementation of these regulations, we recorded a non-cash pre-tax asset impairment charge of $44 million, $33 million after-tax on unproved oil and gas properties in certain California locations during the second quarter of 2024. The impairment represents approximately 2% of the gross cost basis of our total oil and natural gas properties. See Note 10—Oil and Natural Gas Properties to the Financial Statements.

In addition to the permitting requirements above, by January 1, 2025, all wells and facilities within the setback must be in compliance with specific health, safety and environmental requirements pursuant to SB 1137 and have developed and submitted to CalGEM leak detection and response plans for agency approval. We do not expect this law to result in any material change to our overall existing proved developed producing reserves or current production rates.

Other Legislation

The potential exists for additional legislation in the future that could adversely impact our operations. For example, in 2023, a legislator introduced Senate Bill No. 556 (SB 556) into the California Senate in 2023, 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 in a setback zone, subject to limited defenses. SB 556 also provided for civil penalties to be assessed against potentially responsible parties. Although this bill died during the last legislative session, an identical bill—Assembly Bill 3155 (AB 3155)—was introduced into the California Legislature in early 2024 and is currently under consideration. Separately, Assembly Bill 2716 (AB 2716) was introduced in 2024, which would require the plugging and abandonment of certain low-production wells located within 3,200 feet of a sensitive receptor within a certain timeframe or otherwise subjects operators to administrative penalties.

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 for the acquired assets to mitigate the potential risk of an increase in the number of orphaned wells becoming state liabilities following the implementation of the law. Similar to AB 1167, in early 2024, a California legislator introduced Assembly Bill 1866 (AB 1866) which would require the operator of any idle well to file, on or before July 1, 2025, a plan with the state to provide for the management and elimination of all idle wells, with consideration shown to a number of specified factors when prioritizing idle wells for testing or plugging and abandonment. Additionally, AB 1866 would require operators to restore the surface of the well pad to as near a natural state as practicable or to a condition suitable for alternative use.

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 would be effective for public and private companies with total annual revenues exceeding $1 billion and that do business in California. 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. Both SB 253 and 261 have been challenged in the U.S. District Court for the Central District of California.

In July 2024 the California Governor signed a bill that limits the use of California net operating losses (“NOLs”) and we determined there is no impact to the carrying value of and ability to utilize our California NOLs. The legislation suspended the use of the California NOL deduction for corporate taxpayers with California net income or modified adjusted gross income of $1 million or more for tax years beginning on or after January 1, 2024, and before January 1, 2027. Currently there is no impact to Berry, but there could be a future impact to our carrying value and ability to utilize our California NOLs.

Inflation

The U.S. inflation rate has become more significant in recent years. 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. During the first half of 2024, inflation rates have continued their trend of stabilizing as seen in the latter half of 2023. We are unable to accurately predict if such inflationary pressures and contributing factors will continue through the remainder of 2024. However, as of June 30, 2024, we determined there have not been any material changes in inflationary pressures since the year ended December 31, 2023.

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.

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. In the second quarter of 2024, gas prices decreased from prices in the first quarter of 2024. 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.

Capital Expenditures

For the three and six months ended June 30, 2024, our total capital expenditures were approximately $42 million and $59 million, respectively, including capitalized overhead and interest and excluding acquisitions and asset retirement spending. E&P and corporate expenditures were $42 million and $57 million for the three and six months ended June 30, 2024, respectively (excluding well servicing and abandonment capital of less than $1 million and $2 million for the three and six months ended June 30, 2024, respectively). Approximately 70% and 30% of these capital expenditures for the six months ended June 30, 2024 were directed to California and Utah operations, respectively. During the first six months of 2024 we drilled 24 wells in California, four vertical wells in Utah and four non-operated wells in Utah, of which our interest is approximately 21%.

Our 2024 capital expenditure budget for E&P operations, CJWS and corporate activities is expected to be between $95 to $110 million, which, if executed fully, we expect to result in 2024 production consistent with 2023. We currently anticipate oil production will be approximately 93% of total production volume in 2024, substantially consistent with 2023. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund the remainder of our 2024 capital development programs from cash flow from operations. Our current capital program for 2024 focuses on sidetracks and workovers in California, and also includes the Utah development noted above. Additionally, our 2024 capital program includes the drilling of one or more of the new wells approved by CalGEM in May 2024. We also expect our 2024 results to benefit from a full year of production from the California assets acquired in the second half of 2023, as well as from the production from the additional California assets acquired in the second quarter of 2024 and the Utah horizontal farm-in well interests which came online in June 2024, all of which should help maintain consistent production in 2024 if we execute fully on our 2024 capital budget. 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 the assumption that we would not receive additional new well drilling permits in California in 2024, but that we would continue to timely receive the other permits and approvals needed for planned activities. We did receive new well permits in the second quarter which are now factored into our development program for 2024. However, as discussed elsewhere in this Quarterly Report, we continue to see delays in our ability to timely obtain workover and sidetrack permits, in addition to new drill permits. 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 2024, we plan to spend approximately $21 million to $24 million on plugging and abandonment activities, most of which is planned to meet our annual obligation requirements under California idle well program. We spent approximately $3 million and $5 million for plugging and abandonment activities in the three months and six months ended June 30, 2024, respectively.

For information about the potential risks related to our capital program, see Part I, Item IA. "Risk factors" in our Annual Report, as well as "—Regulatory Matters."

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		
	June 30, 2024	March 31, 2024	June 30, 2023
Average daily production:[1]			
Oil (mbbl/d)	23.4	23.8	24.0
Natural Gas (mmcf/d)	8.9	7.9	9.2
NGL (mbbl/d)	0.4	0.3	0.4
Total (mboe/d)[2]	25.3	25.4	25.9
Total Production:			
Oil (mbbl)	2,129	2,161	2,186
Natural gas (mmcf)	808	723	839
NGLs (mbbl)	36	28	35
Total (mboe)[2]	2,300	2,310	2,361
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 78.18	$ 75.31	$ 70.68
Effects of scheduled derivative settlements ($/bbl)	$ (4.60)	$ (2.17)	$ (0.81)
Oil with hedges ($/bbl)	$ 73.58	$ 73.14	$ 69.87
Natural gas ($/mcf)	$ 1.78	$ 3.76	$ 2.87
NGL ($/bbl)	$ 24.46	$ 29.60	$ 22.16
Average Benchmark prices:			
Oil (bbl) – Brent	$ 85.03	$ 81.76	$ 77.73
Oil (bbl) – WTI	$ 80.60	$ 77.02	$ 73.73
Natural gas (mmbtu) – SoCal Gas city-gate[3]	$ 1.86	$ 4.21	$ 5.66
Natural gas (mmbtu) – Northwest, Rocky Mountains[4]	$ 1.40	$ 3.41	$ 2.85
Natural gas (mmbtu) – Henry Hub[4]	$ 2.07	$ 2.15	$ 2.16

(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 June 30, 2024, the average prices of Brent oil and Henry Hub natural gas were $85.03 per bbl and $2.07 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.

(4) Most of our gas purchases and gas sales in the Rockies are predicated on the Northwest, Rocky Mountains index, and to a lesser extent based on Henry Hub.

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

	Three Months Ended		
	June 30, 2024	March 31, 2024	June 30, 2023
Average daily production (mboe/d):[(1)]			
California	21.1	21.3	20.8
Utah	4.2	4.1	5.1
Total average daily production	25.3	25.4	25.9

(1) Production represents volumes sold during the period.

Our average daily production decreased less than 1%, or 0.1 mboe/d, for the three months ended June 30, 2024, compared to the three months ended March 31, 2024. Our California production was 21.1 mboe/d for the second quarter of 2024, a decrease of 1% or 0.2 mboe/d from the first quarter of 2024, which was principally due to natural well decline as well as increased downtime due to drilling, plugging and abandoning activities. This decrease was partially offset by higher production from the optimization of certain new wells. The Utah increase was due to our recent investment in four non-operated wells which began production in June as well as warmer, more favorable, weather conditions for gas production.

Our average daily production decreased 2%, or 0.6 mboe/d, for the three months ended June 30, 2024 compared to the three months ended June 30, 2023. Higher 2024 production in California was due to the bolt-on acquisitions purchased in late 2023 and increased well operating time from improved weather conditions and less abandonment activity. The decrease in Utah was due to natural well decline as recently drilled wells were not online in the period.

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

	Six Months Ended	
	June 30, 2024	June 30, 2023
Average daily production:[1]		
Oil (mbbl/d)	23.6	23.3
Natural Gas (mmcf/d)	8.4	8.9
NGL (mbbl/d)	0.4	0.3
Total (mboe/d)[2]	25.4	25.1
Total Production:		
Oil (mbbl)	4,290	4,223
Natural gas (mmcf)	1,531	1,618
NGLs (mbbl)	64	55
Total (mboe)[2]	4,610	4,548
Weighted-average realized sales prices:		
Oil without hedges ($/bbl)	$ 76.73	$ 72.62
Effects of scheduled derivative settlements ($/bbl)	$ (3.38)	$ (2.18)
Oil with hedges ($/bbl)	$ 73.35	$ 70.44
Natural gas ($/mcf)	$ 2.72	$ 9.86
NGL ($/bbl)	$ 26.74	$ 26.48
Average Benchmark prices:		
Oil (bbl) – Brent	$ 83.42	$ 79.96
Oil (bbl) – WTI	$ 78.81	$ 74.94
Natural gas (mmbtu) – SoCal Gas city-gate[3]	$ 3.03	$ 15.23
Natural gas (mmbtu) – Northwest, Rocky Mountains[4]	$ 2.40	$ 12.61
Natural gas (mmbtu) – Henry Hub[4]	$ 2.11	$ 2.40

(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 six months ended June 30, 2024, the average prices of Brent oil and Henry Hub natural gas were $83.42 per bbl and $2.11 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.

(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:

	Six Months Ended	
	June 30, 2024	June 30, 2023
Average daily production (mboe/d):[1]		
California	21.2	20.4
Utah	4.2	4.7
Total average daily production	25.4	25.1

(1) Production represents volumes sold during the period.

Average daily production for the six months ended June 30, 2024 increased by 0.3 mboe/d, or 1%, compared to the same period in 2023. California produced 21.2 mboe/d for the six months ended June 30, 2024, an increase of 0.8 mboe/d, or 4%, when compared to the six months ended June 30, 2023 due primarily to the acquisition of the Round Mountain asset in late 2023. Average daily production in Utah for the six months ending June 30, 2024 decreased by 0.5 mboe/d, or 11% compared to the same period in 2023 due to natural well decline and a reduced capital program, limiting new drilling and workover activities in Utah.

Results of Operations

Three Months Ended June 30, 2024 compared to Three Months Ended March 31, 2024.

	Three Months Ended			
	June 30, 2024	March 31, 2024	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 168,781	$ 166,318	$ 2,463	1 %
Service revenue[1]	31,155	31,683	(528)	(2)%
Electricity sales	3,691	4,243	(552)	(13)%
(Losses) on oil and gas sales derivatives	(5,844)	(71,200)	65,356	92 %
Other revenues	36	67	(31)	(46)%
Total revenues and other	$ 197,819	$ 131,111	$ 66,708	51 %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $37 million and $35 million and the intercompany elimination was $6 million and $4 million for the quarters ended June 30, 2024 and March 31, 2023, respectively.

Revenues and Other

Oil, natural gas and NGL sales increased by $2 million, or 1%, to approximately $169 million for the three months ended June 30, 2024, compared to the three months ended March 31, 2024. The increase was driven by a $6 million increase in oil prices partially offset by a $2 million decrease in oil volumes and a $2 million decrease in gas prices.

Service revenue consisted entirely of revenue from the well servicing and abandonment business, excluding intercompany amounts. Service revenue was essentially flat at $31 million for the three months ended June 30, 2024, compared to the three months ended March 31, 2024.

Electricity sales represent sales to utilities were essentially flat at $4 million for the three months ended June 30, 2024 compared to the three months ended March 31, 2024.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement loss for the three months ended June 30, 2024 and March 31, 2024 was $10 million and $5 million, respectively. This quarter-over-quarter increase in settlement loss was primarily due to higher Brent settlement prices, the index for all our oil derivatives. The mark-to-market non-cash gain for the three months ended June 30, 2024 was $4 million compared to a loss of $67 million in the three months ended March 31, 2024. 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).

	Three Months Ended			
	June 30, 2024	March 31, 2024	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 53,989	$ 60,697	$ (6,708)	(11)%
Costs of services[(1)]	25,021	27,304	(2,283)	(8)%
Electricity generation expenses	552	1,093	(541)	(49)%
Transportation expenses	1,039	1,059	(20)	(2)%
Acquisition costs[(2)]	1,394	2,617	(1,223)	(47)%
General and administrative expenses	18,881	20,234	(1,353)	(7)%
Depreciation, depletion and amortization	42,843	42,831	12	— %
Impairment of oil and gas properties	43,980	—	43,980	100 %
Taxes, other than income taxes	12,674	15,689	(3,015)	(19)%
Losses on natural gas purchase derivatives	2,642	4,481	(1,839)	(41)%
Other operating (income)	(3,204)	(133)	(3,071)	(2,309)%
Total expenses and other	199,811	175,872	23,939	14 %
Other expenses:				
Interest expense	(10,050)	(9,140)	(910)	10 %
Other, net	(53)	(83)	30	(36)%
Total other expenses	(10,103)	(9,223)	(880)	10 %
(Loss) before income taxes	(12,095)	(53,984)	41,889	78 %
Income tax (benefit)	(3,326)	(13,900)	10,574	(76)%
Net (loss)	$ (8,769)	$ (40,084)	$ 31,315	78 %
Adjusted EBITDA[(3)]	$ 74,329	$ 68,534	$ 5,795	8 %
Adjusted Net Income[(3)]	$ 14,155	$ 10,910	$ 3,245	30 %

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(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, costs of services was $31 million and $31 million and the intercompany elimination was $6 million and $4 million for the three months ended June 30, 2024 and March 31, 2024, respectively.

(2) Includes legal and other professional expenses related to various transaction activities.

(3) 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 11% or $7 million to $54 million for the second quarter of 2024 when compared to the first quarter of 2024. This decrease was the result of lower natural gas (fuel) costs of $8 million for our California steam generation facilities due to a decline in both fuel prices and volumes. The decline in volumes is a result of our cost saving initiatives to reduce steam. Lease operating expenses, excluding fuel, increased $1 million due to higher well service and maintenance activity.

Costs of services consisted entirely of costs from the well servicing and abandonment business, excluding intercompany amounts. Cost of services decreased $2 million, or 8%, to $25 million in the second quarter of 2024 due to cost savings efforts in the second quarter of 2024.

Electricity generation expense decreased $1 million due to lower fuel prices for the three months ended June 30, 2024 compared to the three months ended March 31, 2024.

Gains and losses on natural gas purchase derivatives resulted in a loss of $3 million for the three months ended June 30, 2024 and a loss of $4 million for the three months ended March 31, 2024. Settlements for the three months ended June 30, 2024 and March 31, 2024 were a loss of $9 million, or $4.05 per boe, and a loss of $4 million, or $1.91 per boe, respectively. The increased loss was due to a decrease in settlement price relative to the fixed price in the second quarter of 2024 compared to the first quarter of 2024. The mark-to-market valuation gain for the three months ended June 30, 2024 was $7 million compared to a loss of less than $1 million for the three months ended March 31, 2024. 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 decreased $1 million for the three months ended June 30, 2024 compared to the three months ended March 31, 2024, and include legal and other professional expenses related to various transaction activities.

General and administrative expenses decreased $1 million or 7% to $19 million for the three months ended June 30, 2024, compared to the three months ended March 31, 2024. For the three months ended June 30, 2024, general and administrative expenses included $2 million non-cash stock compensation costs, compared to immaterial amounts for three months ended March 31, 2024. We had no non-recurring costs for the three months ended June 30, 2024 and $1 million for the three months ended March 31, 2024.

Adjusted General and Administrative Expenses, which excludes non-cash stock compensation expense and non-recurring costs, decreased $2 million primarily due to lower payroll related costs for the three months ended June 30, 2024 compared to the three months ended March 31, 2024, due to cost savings initiatives implemented in the first quarter of 2024. See “—Non-GAAP Financial Measures” for a reconciliation of general and administrative expenses, 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 June 30, 2024 compared to the three months ended March 31, 2024.

Impairment of Oil and Gas Properties

Impairment of oil and gas properties was $44 million for the three months ended June 30, 2024. There was no impairment of oil and gas properties for the three months ended March 31, 2024.

Taxes, Other Than Income Taxes

	Three Months Ended			
	June 30, 2024	**March 31, 2024**	**$ Change**	**% Change**
	(per boe)			
Severance taxes	$ 1.72	$ 1.67	$ 0.05	3 %
Ad valorem and property taxes	2.14	2.51	(0.37)	(15)%
Greenhouse gas allowances and other emission costs	1.65	2.61	(0.96)	(37)%
Total taxes other than income taxes	$ 5.51	$ 6.79	$ (1.28)	(19)%

Taxes, other than income taxes, decreased in the three months ended June 30, 2024 by $1.28 per boe, or 19%, to $5.51. The decrease was primarily due to lower GHG expense where the quarter-over-quarter mark-to-market price of emissions credits decreased 7%.

Other Operating (Income) Expenses

For the three months ended June 30, 2024, other operating income was $3 million and mainly consisted of prior period royalty receipts and property tax refunds.

Interest Expense

Interest expense increased $1 million for the three months ended June 30, 2024, compared to the three months ended March 31, 2024 as we had higher working capital borrowings on the RBL Facility.

Income Taxes

Our effective tax rate was 28% for the three months ended June 30, 2024 and 26% for the three months ended March 31, 2024. The rate in both periods included the impact of certain permanent items which were not deductible and the utilization of tax credits.

Three Months Ended June 30, 2024 compared to Three Months Ended June 30, 2023.

	Three Months Ended June 30,			
	2024	2023	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 168,781	$ 157,703	$ 11,078	7 %
Service revenue[1]	31,155	47,674	(16,519)	(35)%
Electricity sales	3,691	3,078	613	20 %
(Losses) gains on oil and gas sales derivatives	(5,844)	20,871	(26,715)	n/a
Other revenues	36	36	—	— %
Total revenues and other	$ 197,819	$ 229,362	$ (31,543)	(14)%

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $37 million and $49 million and the intercompany elimination was $6 million and $2 million for the quarters ended June 30, 2024 and 2023, respectively.

Revenues and Other

Oil, natural gas and NGL sales increased $11 million to approximately $169 million for the three months ended June 30, 2024 when compared to the three months ended June 30, 2023. $16 million of the increase was due to an increase in oil prices, partially offset by a $4 million decrease in oil volumes and a $1 million decrease in gas prices.

Service revenue (excluding intercompany amounts) decreased by $17 million to $31 million for the three months ended June 30, 2024, compared to the three months ended June 30, 2023, due to lower activity and a shift in service from third parties to our E&P segment.

Electricity sales represent sales to utilities and are essentially flat at $4 million for the three months ended June 30, 2024 when compared to the three months ended June 30, 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 June 30, 2024 and June 30, 2023 were $10 million and $2 million, respectively. The increase in settlement losses was driven by higher oil prices relative to our derivative fixed prices in the first quarter of 2024 than that of the same period in 2023. Notional volumes were 18 mbbl/d in the second quarter of 2024 and 15 mbbl/d in the second quarter of 2023. The mark-to-market non-cash gain for the three months ended June 30, 2024 was $4 million and $23 million for 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).

	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 53,989	$ 54,707	$ (718)	(1)%
Costs of services[1]	25,021	37,083	(12,062)	(33)%
Electricity generation expenses	552	1,273	(721)	(57)%
Transportation expenses	1,039	1,096	(57)	(5)%
Acquisition costs[2]	1,394	972	422	43 %
General and administrative expenses	18,881	22,488	(3,607)	(16)%
Depreciation, depletion and amortization	42,843	39,755	3,088	8 %
Impairment of oil and gas properties	43,980	—	43,980	100 %
Taxes, other than income taxes	12,674	13,707	(1,033)	(8)%
Losses on natural gas purchase derivatives	2,642	14,024	(11,382)	(81)%
Other operating (income)	(3,204)	(1,033)	(2,171)	(210)%
Total expenses and other	199,811	184,072	15,739	9 %
Other expenses:				
Interest expense	(10,050)	(8,794)	(1,256)	14 %
Other, net	(53)	(110)	57	(52)%
Total other expenses	(10,103)	(8,904)	(1,199)	13 %
(Loss) income before income taxes	(12,095)	36,386	(48,481)	(133)%
Income tax (benefit) expense	(3,326)	10,616	(13,942)	131 %
Net (loss) income	$ (8,769)	$ 25,770	$ (34,539)	(134)%
Adjusted EBITDA[3]	$ 74,329	$ 69,055	$ 5,274	8 %
Adjusted Net Income[3]	$ 14,155	$ 11,666	$ 2,489	21 %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, costs of services was $31 million and $39 million and the intercompany elimination was $6 million and $2 million for the quarters ended June 30, 2024 and June 30, 2023, respectively.

(2) Includes legal and other professional expenses related to various transactions activities.

(3) 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 1% or $1 million on an absolute dollar basis to $54 million for the second quarter of 2024 when compared to the second quarter of 2023. The decrease was the result of $6 million lower natural gas (fuel) costs for our California steam generation facilities mainly due to lower volumes purchased, as a result of our cost savings initiatives to reduce steam, and a decline in fuel prices. These decreases were partially offset by a $5 million increase in non-fuel lease operating expense from higher power costs, and from increased well servicing activity.

Cost of services (excluding intercompany amounts) decreased $12 million, or 33%, to $25 million for the second quarter of 2024 compared to the second quarter of 2023 primarily due to cost savings in response to lower activity.

Electricity generation expenses decreased $1 million, or 57%, to $1 million for the three months ended June 30, 2024 compared to the same period in 2023 due to a decrease in fuel prices.

Gains and losses on natural gas purchase derivatives for the three months ended June 30, 2024 and June 30, 2023 resulted in a loss of $3 million and a loss of $14 million, respectively. Settlements for the three months ended June 30, 2024 were a loss of $9 million, or $4.05 per boe, and a loss of $11 million or $4.55 per boe for the three months ended June 30, 2023. The change in settlement loss was due to a decline in the fixed price of settled positions. The mark-to-market non-cash gain was $7 million for the three months ended June 30, 2024 and a loss of $3 million for 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).

Transportation expenses were comparable for the periods presented.

Acquisition costs were flat for the three months ended June 30, 2024 compared to the three months ended June 30, 2023, and include legal and other professional expenses related to various transaction activities.

General and administrative expenses decreased $4 million or 16% in the three months ended June 30, 2024 when compared to the three months ended June 30, 2023. For the three months ended June 30, 2024 general and administrative expenses had $2 million in non-cash stock compensation expense compared to $3 million for June 30, 2023. We incurred no non-recurring costs for the three months ended June 30, 2024 and three months ended June 30, 2023.

Adjusted General and Administrative Expenses, which exclude non-cash stock compensation expense and non-recurring costs decreased $2 million for the three months ended June 30, 2024 compared to the three months ended June 30, 2023. The decrease was the result of lower employee compensation and reduced professional services, due to cost savings initiatives implemented in the first quarter of 2024. See "—Non-GAAP Financial Measures" for a reconciliation of general and administrative expenses, the most directly comparable financial measure calculated and presented in accordance with GAAP, to Adjusted General and Administrative Expenses.

DD&A increased $3 million, or 8%, to $43 million in the three months ended June 30, 2024 when compared to the three months ended June 30, 2023 due to an increase in depletion rates.

Impairment of Oil and Gas Properties

Impairment of oil and gas properties was $44 million for the three months ended June 30, 2024. There was no impairment of oil and gas properties for the three months ended June 30, 2023.

Taxes, Other Than Income Taxes

	Three Months Ended June 30,			
	2024	2023	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.72	$ 1.44	$ 0.28	19 %
Ad valorem and property taxes	2.14	1.87	0.27	14 %
Greenhouse gas allowances and other emission costs	1.65	2.50	(0.85)	(34)%
Total taxes other than income taxes	$ 5.51	$ 5.81	$ (0.30)	(5)%

Taxes, other than income taxes decreased 5% to $5.51 per boe for the three months ended June 30, 2024, compared to $5.81 per boe for the three months ended June 30, 2023. GHG allowance expense decreased due to mark-to-market price declines in the second quarter of 2024 compared to increases in the second quarter of 2023 The increase in ad valorem and property taxes is due to increased property values in due in part to the additional properties acquired in 2023.

Other Operating (Income) Expenses

For the three months ended June 30, 2024, other operating income was $3 million and mainly consisted of prior period royalty receipts and property tax refunds. For three months ended June 30, 2023, other income was $1 million, primarily due to a 2017 property tax refund.

Interest Expense

Interest expense increased $1 million, or 14%, in the three months ended June 30, 2024 when compared to the three months ended June 30, 2023 as we had higher working capital borrowings on the RBL Facility.

Income Taxes

Our effective tax rate was approximately 28% for the three months ended June 30, 2024 compared to approximately 29% for the three months ended June 30, 2023. The rate in both periods included the impact of certain permanent items which were not deductible and the utilization of tax credits.

Six Months Ended June 30, 2024 compared to Six Months Ended June 30, 2023.

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 335,099	$ 324,060	$ 11,039	3 %
Service revenue[(1)]	62,838	92,297	(29,459)	(32)%
Electricity sales	7,934	8,523	(589)	(7)%
(Losses) gains on oil and gas sales derivatives	(77,044)	59,370	(136,414)	n/a
Other revenues	103	81	22	27 %
Total revenues and other	$ 328,930	$ 484,331	$ (155,401)	(32)%

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, service revenue was approximately $72 million and $96 million and the intercompany elimination was $9 million and $3 million for the six months ended June 30, 2024 and 2023, respectively.

Revenues and Other

Oil, natural gas and NGL sales increased $11 million, or 3%, to $335 million for the six months ended June 30, 2024 when compared to the six months ended June 30, 2023. The variance was mainly driven by an increase in oil prices, partially offset by a decrease in gas prices.

Service revenue (excluding intercompany amounts) decreased $29 million, or 32%, to $63 million for the six months ended June 30, 2024 when compared to the six months ended June 30, 2023, due to lower activity and a shift in service from third parties to our E&P segment.

Electricity sales, which represent sales to utilities are essentially flat at $8 million for the six months ended June 30, 2024 when compared to the six months ended June 30, 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 six months ended June 30, 2024 and June 30, 2023 were $14 million and $9 million, respectively. The period-over-period increase in settlement losses was driven by a wider spread between the settled derivative fixed prices and index oil prices in the six months ended June 30, 2024 compared to that of the same period in 2023. The mark-to-market non-cash loss was $63 million for the six months ended June 30, 2024 and a gain of $69 million for the six 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).

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023	$ Change	% Change
	(in thousands)			
Expenses and other:				
Lease operating expenses	$ 114,686	$ 189,542	$ (74,856)	(39)%
Costs of services[1]	52,325	73,182	(20,857)	(29)%
Electricity generation expenses	1,645	3,773	(2,128)	(56)%
Transportation expenses	2,098	2,137	(39)	(2)%
Acquisition costs[2]	4,011	972	3,039	313 %
General and administrative expenses	39,115	54,157	(15,042)	(28)%
Depreciation, depletion and amortization	85,674	79,876	5,798	7 %
Impairment of oil and gas properties	43,980	—	43,980	100 %
Taxes, other than income taxes	28,363	24,167	4,196	17 %
Losses on natural gas purchase derivatives	7,123	13,414	(6,291)	(47)%
Other operating (income)	(3,337)	(1,319)	(2,018)	(153)%
Total expenses and other	375,683	439,901	(64,218)	(15)%
Other (expenses) income:				
Interest expense	(19,190)	(16,631)	(2,559)	15 %
Other, net	(136)	(185)	49	(26)%
Total other expenses	(19,326)	(16,816)	(2,510)	15 %
(Loss) income before income taxes	(66,079)	27,614	(93,693)	(339)%
Income tax (benefit) expense	(17,226)	7,703	(24,929)	324 %
Net (loss) income	$ (48,853)	$ 19,911	$ (68,764)	(345)%
Adjusted EBITDA[3]	$ 142,863	$ 128,392	$ 14,471	11 %
Adjusted Net Income[3]	$ 25,065	$ 16,973	$ 8,092	48 %

(1) The well servicing and abandonment segment occasionally provides services to our E&P segment. Prior to the intercompany elimination, costs of services was $62 million and $77 million and the intercompany elimination was $9 million and $3 million for the six months ended June 30, 2024 and June 30, 2023, respectively.

(2) Includes legal and other professional expenses related to various transaction activities.

(3) 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 39%, or $75 million, on an absolute dollar basis to $115 million for the six months ended June 30, 2024 when compared to the six months ended June 30, 2023. The decrease was due to an $82 million decrease in natural gas (fuel) costs for our California steam generation facilities due to a decline in fuel prices. Lease operating expenses excluding fuel increased $7 million due to higher power costs and well servicing activity.

Cost of services (excluding intercompany amounts) decreased $21 million, or 29%, to $52 million in the six months ended June 30, 2024, due to cost savings in response to lower activity.

Electricity generation expenses decreased $2 million to $2 million for the six months ended June 30, 2024 compared to the same period in 2023 due to lower fuel prices and decreased volumes. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements.

Gains and losses on natural gas purchase derivatives for the six months ended June 30, 2024 and June 30, 2023 consisted of a loss of $7 million and $13 million, respectively. In the six months ended June 30, 2024 the natural gas settlement price was less than the fixed price of settled positions which resulted in a settlement loss of $14 million, compared to the same period in 2023 when the natural gas settlement price was greater than the fixed prices of settled positions which resulted in a settlement gain of $44 million. The mark-to-market valuation for the six months ended June 30, 2024 was a gain of $7 million compared to a loss of $58 million for the same period in 2023 due to lower futures prices relative to our derivative fixed prices at June 30, 2024 compared to those at 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).

Transportation expenses were comparable for the periods presented.

Acquisition costs increased $3 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023, and includes legal and professional expenses related to various transaction activities.

General and administrative expenses decreased $15 million, or 28%, to approximately $39 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023. For the six months ended June 30, 2024 and June 30, 2023, general and administrative expenses included non-cash stock compensation costs of approximately $2 million and $8 million, respectively. We incurred non-recurring costs of $1 million for the six months ended June 30, 2024. For the six months ended June 30, 2023 we incurred non-recurring costs of $7 million, which were related to executive transition costs and workforce reduction costs in the first quarter of 2023.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, decreased $3 million to $36 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 due to lower payroll related costs, resulting from cost savings initiatives implemented in the first quarter of 2024. 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 $6 million, or 7%, to $86 million for the six months ended June 30, 2024 compared to the six months ended June 30, 2023 due to an increase in depletion rates.

Impairment of Oil and Gas Properties

Impairment of oil and gas properties was $44 million for the six months ended June 30, 2024. There was no impairment of oil and gas properties for the six months ended June 30, 2023.

Taxes, Other Than Income Taxes

	Six Months Ended June 30,			
	2024	**2023**	**$ Change**	**% Change**
	(per boe)			
Severance taxes	$ 1.69	$ 1.61	$ 0.08	5 %
Ad valorem and property taxes	2.33	2.03	0.30	15 %
Greenhouse gas allowances and other emission costs	2.13	1.67	0.46	28 %
Total taxes other than income taxes	$ 6.15	$ 5.31	$ 0.84	16 %

Taxes, other than income taxes increased 16% to $6.15 per boe for the six months ended June 30, 2024 compared to $5.31 per boe for the six months ended June 30, 2023. GHG allowance expense increased due to higher non-cash mark-to-market prices for the allowances compared to the same period in 2023. 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 six months ended June 30, 2024, other operating income was $3 million and mainly consisted of prior period royalty receipts and property tax refunds. For the six months ended June 30, 2023, other operating income was $1 million and mainly consisted of a 2017 property tax refund.

Interest Expense

Interest expense increased $3 million, or 15%, in the six months ended June 30, 2024 compared to the same period in 2023 as a result of higher working capital borrowings on the RBL Facility in 2023.

Income Taxes

Our effective tax rate was approximately 26% for the six months ended June 30, 2024, compared to 28% for the six months ended June 30, 2023, respectively. The rate for the six months ended June 30, 2024 was impacted by the book loss in the second quarter of 2024, which included the impact of certain permanent items that are not deductible for tax purposes.

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.

E&P Field Operations

	Three Months Ended June 30, 2024	Three Months Ended March 31, 2024	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 23.47	$ 26.28	$ (2.81)	(11)%
Electricity generation expenses	0.24	0.47	(0.23)	(49)%
Transportation expenses	0.45	0.46	(0.01)	(2)%
Total	$ 24.16	$ 27.21	$ (3.05)	(11)%
Cash settlements paid for gas purchase hedges	$ 4.05	$ 1.91	$ 2.14	112 %
E&P non-production revenues				
Electricity sales	$ 1.60	$ 1.84	$ (0.24)	(13)%
Transportation sales	0.02	0.03	(0.01)	(33)%
Total	$ 1.62	$ 1.87	$ (0.25)	(13)%

	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 23.47	$ 23.17	$ 0.30	1 %
Electricity generation expenses	0.24	0.54	(0.30)	(56)%
Transportation expenses	0.45	0.46	(0.01)	(2)%
Total	$ 24.16	$ 24.17	$ (0.01)	0 %
Cash settlements paid for gas purchase hedges	$ 4.05	$ 4.56	$ (0.51)	(11)%
E&P non-production revenues				
Electricity sales	$ 1.60	$ 1.30	$ 0.30	23 %
Transportation sales	0.02	0.02	—	— %
Total	$ 1.62	$ 1.32	$ 0.30	23 %

	Six Months Ended			
	June 30, 2024	June 30, 2023	$ Change	% Change
	(per boe)			
Expenses from field operations				
Lease operating expenses	$ 24.88	$ 41.68	$ (16.80)	(40)%
Electricity generation expenses	0.36	0.83	(0.47)	(57)%
Transportation expenses	0.46	0.47	(0.01)	(2)%
Total	$ 25.70	$ 42.98	$ (17.28)	(40)%
Cash settlements paid (received) for gas purchase hedges	$ 2.98	$ (9.71)	$ 12.69	(131)%
E&P non-production revenues				
Electricity sales	$ 1.72	$ 1.87	$ (0.15)	(8)%
Transportation sales	0.02	0.02	—	— %
Total	$ 1.74	$ 1.89	$ (0.15)	(8)%

See "—How We Plan and Evaluate Operations" for details.

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 expenditure 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 Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and capital expenditures. In 2024, we updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and capital expenditures. This update better aligns with the full capital expenditure requirements of the Company. For 2023, Adjusted Free Cash Flow was defined as cash flow from operations less regular fixed dividends and maintenance capital. 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.

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 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 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			Six Months Ended	
	June 30, 2024	March 31, 2024	June 30, 2023	June 30, 2024	June 30, 2023
	(in thousands)				
Adjusted EBITDA reconciliation:					
Net (loss) income	$ (8,769)	$ (40,084)	$ 25,770	$ (48,853)	$ 19,911
Add (Subtract):					
Interest expense	10,050	9,140	8,794	19,190	16,631
Income tax (benefit) expense	(3,326)	(13,900)	10,616	(17,226)	7,703
Depreciation, depletion and amortization	42,843	42,831	39,755	85,674	79,876
Impairment of oil and gas properties	43,980	—	—	43,980	—
Losses (gains) on derivatives	8,486	75,681	(6,847)	84,167	(45,956)
Net cash (paid) received for scheduled derivative settlements	(19,115)	(9,094)	(12,524)	(28,209)	34,943
Other operating (income)	(3,204)	(133)	(1,033)	(3,337)	(1,319)
Stock compensation expense[(1)]	1,990	385	3,552	2,375	8,318
Acquisition costs[(2)]	1,394	2,617	972	4,011	972
Non-recurring costs[(3)]	—	1,091	—	1,091	7,313
Adjusted EBITDA	$ 74,329	$ 68,534	$ 69,055	$ 142,863	$ 128,392

	Three Months Ended			Six Months Ended	
	June 30, 2024	March 31, 2024	June 30, 2023	June 30, 2024	June 30, 2023
	(in thousands)				
Adjusted EBITDA reconciliation:					
Net cash provided by operating activities	$ 70,891	$ 27,273	$ 62,538	$ 98,164	$ 64,319
Add (Subtract):					
Cash interest payments	1,395	15,256	1,004	16,651	15,392
Cash income tax payments	491	—	670	491	670
Acquisition costs[(2)]	1,394	2,617	—	4,011	—
Non-recurring costs[(3)]	—	1,091	—	1,091	7,313
Changes in operating assets and liabilities - working capital[(4)]	3,293	22,543	6,065	25,836	42,810
Other operating (income) - cash portion[(5)]	(3,135)	(246)	(1,222)	(3,381)	(2,112)
Adjusted EBITDA	$ 74,329	$ 68,534	$ 69,055	$ 142,863	$ 128,392

(1) Decrease in the first quarter of 2024 is the result of stock award forfeitures.

(2) Includes legal and other professional expenses related to various transaction activities.

(3) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

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

(5) Represents the cash portion of other operating (income) 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.

	Three Months Ended			Six Months Ended	
	June 30, 2024	March 31, 2024	June 30, 2023	June 30, 2024	June 30, 2023
			(in thousands)		
Adjusted Free Cash Flow reconciliation:					
Net cash provided by operating activities[1]	$ 70,891	$ 27,273	$ 62,538	$ 98,164	$ 64,319
Subtract:					
Capital expenditures[2]	(42,325)	(16,936)	(19,625)	(59,261)	(38,897)
Fixed dividends[3]	(9,233)	(9,233)	(9,139)	(18,466)	(18,329)
Adjusted Free Cash Flow	$ 19,333	$ 1,104	$ 33,774	$ 20,437	$ 7,093

(1) On a consolidated basis.

(2) In 2024, we updated Adjusted Free Cash Flow to include all capital expenditures in the calculation of Adjusted Free Cash Flow. This update better aligns with the full capital expenditure requirements of the Company. In 2023, the definition of capital expenditures was the required amount to keep annual production essentially flat (maintenance capital), calculated as the capital expenditures for the E&P business for the periods presented. We did not retrospectively adjust 2023.

	Three Months Ended	Six Months Ended
	June 30, 2023	June 30, 2023
	(in thousands)	
Consolidated capital expenditures[a]	$ (21,895)	$ (42,528)
Excluded items[b]	2,270	3,631
Maintenance capital	$ (19,625)	$ (38,897)

(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 and six months ended June 30, 2023, we excluded approximately $1.3 million and $2.3 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 and six months ended June 30, 2023, we excluded approximately $0.9 million and $1.3 million of corporate capital expenditures, respectively, 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					
	June 30, 2024		March 31, 2024		June 30, 2023	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted	(in thousands)	per share - diluted
Adjusted Net Income (Loss) reconciliation:						
Net (loss) income	$ (8,769)	$ (0.11)	$ (40,084)	$ (0.52)	$ 25,770	$ 0.33
Add (Subtract):						
Losses (gains) on derivatives	8,486	0.11	75,681	0.98	(6,847)	(0.09)
Net cash (paid) received for scheduled derivative settlements	(19,115)	(0.25)	(9,094)	(0.12)	(12,524)	(0.16)
Other operating (income)	(3,204)	(0.05)	(133)	—	(1,033)	(0.01)
Impairment of oil and gas properties	43,980	0.57	—	—	—	—
Acquisition costs(1)	1,394	0.02	2,617	0.03	972	0.01
Non-recurring costs(2)	—	—	1,091	0.02	—	—
Total additions (subtractions), net	31,541	0.40	70,162	0.91	(19,432)	(0.25)
Income tax (benefit) expense of adjustments(3)	(8,617)	(0.11)	(19,168)	(0.25)	5,328	0.07
Adjusted Net Income	$ 14,155	$ 0.18	$ 10,910	$ 0.14	$ 11,666	$ 0.15
Basic EPS on Adjusted Net Income	$ 0.18		$ 0.14		$ 0.15	
Diluted EPS on Adjusted Net Income	$ 0.18		$ 0.14		$ 0.15	
Weighted average shares of common stock outstanding - basic	76,939		76,254		76,721	
Weighted average shares of common stock outstanding - diluted	77,161		77,373		79,285	

(1) Includes legal and other professional expenses related to various transaction activities.

(2) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

(3) The federal and state statutory rates were utilized for all periods presented.

	Six Months Ended			
	June 30, 2024		June 30, 2023	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted
Adjusted Net Income (Loss) reconciliation:				
Net (loss) income	$ (48,853)	$ (0.64)	$ 19,911	$ 0.25
Add (Subtract):				
Losses (gains) on derivatives	84,167	1.10	(45,956)	(0.58)
Net cash (paid) received for scheduled derivative settlements	(28,209)	(0.37)	34,943	0.44
Other operating (income)	(3,337)	(0.03)	(1,319)	(0.01)
Impairment of oil and gas properties	43,980	0.57	—	—
Acquisition costs[1]	4,011	0.05	972	0.01
Non-recurring costs[2]	1,091	0.01	7,313	0.09
Total additions (subtractions), net	101,703	1.33	(4,047)	(0.05)
Income tax (benefit) expense of adjustments[3]	(27,785)	(0.36)	1,109	0.01
Adjusted Net Income	$ 25,065	$ 0.33	$ 16,973	$ 0.21
Basic EPS on Adjusted Net Income	$ 0.33		$ 0.22	
Diluted EPS on Adjusted Net Income	$ 0.33		$ 0.21	
Weighted average shares of common stock outstanding - basic	76,597		76,419	
Weighted average shares of common stock outstanding - diluted	76,860		79,575	

(1) Includes legal and other professional expenses related to various transaction activities.

(2) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

(3) The federal and state statutory rates were utilized for all periods presented.

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			Six Months Ended	
	June 30, 2024	March 31, 2024	June 30, 2023	June 30, 2024	June 30, 2023
			(in thousands)		
Adjusted General and Administrative Expense reconciliation:					
General and administrative expenses	$ 18,881	$ 20,234	$ 22,488	$ 39,115	$ 54,157
Subtract:					
Non-cash stock compensation expense (G&A portion)(1)	(1,843)	(200)	(3,379)	(2,043)	(7,998)
Non-recurring costs(2)	—	(1,091)	—	(1,091)	(7,313)
Adjusted general and administrative expenses	$ 17,038	$ 18,943	$ 19,109	$ 35,981	$ 38,846
Well servicing and abandonment segment	$ 2,454	$ 2,929	$ 2,958	$ 5,383	$ 6,084
E&P segment, and corporate	$ 14,584	$ 16,014	$ 16,151	$ 30,598	$ 32,762
E&P segment, and corporate ($/boe)	$ 6.34	$ 6.93	$ 6.84	$ 6.64	$ 7.20
Total mboe	2,300	2,310	2,361	4,610	4,548

(1) Decrease in the first quarter of 2024 is the result of stock award forfeitures.

(2) In 2024, non-recurring costs included workforce reduction costs in the first quarter. In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter.

Liquidity and Capital Resources

As of June 30, 2024, we had liquidity of $169 million, consisting of $7 million cash, $155 million available for borrowings under our 2021 RBL Facility and $7 million available for borrowings under our 2022 ABL Facility (as defined below). As of July 31, 2024, we reduced our borrowings outstanding under the 2021 RBL Facility to $28 million. Based on current commodity prices and our development success rate to date, we expect to be able to fund the remainder of our 2024 capital development programs from cash flow from operations.

We review the allocations under our shareholder return model from time to time based on industry conditions, operational results, contractual restrictions and other factors. We believe it is likely in future periods that we may have additional restrictions on dividends and share repurchases under any debt agreement we may enter into in connection with refinancing our 2026 Notes (as defined below) or that we will need to reduce such amounts and allocate additional funds to debt repayment. Also, in 2024, we updated the definition of Adjusted Free Cash Flow, a non-GAAP measure, as cash flow from operations less regular fixed dividends and all capital expenditures. For 2023, Adjusted Free Cash Flow was defined as cash flow from operations less regular fixed dividends and maintenance capital. Our goal is to continue maximizing enterprise value through overall returns. Beginning in 2023, the annual allocation of Adjusted Free Cash Flow has been (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, including any agreements we may enter into in the future in connection with refinancing our 2026 Notes, business conditions and other factors. From time to time we consider bolt-on acquisitions, which may be used to maintain our existing production volumes or may support strategic growth, and could be at least partially funded by reallocating a portion of our capital expenditures, as a way of increasing Adjusted Free Cash Flow.

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.

Our 2026 Notes mature in February 2026. We are currently evaluating prospective financing arrangements to refinance our 2026 Notes and extend the maturity date of the 2021 RBL Facility. We may not be successful in refinancing, repaying or extending the maturity of our 2026 Notes or our 2021 RBL Facility, and any such refinancing may not be obtainable on terms favorable to us. If we are unable to refinance the 2026 Notes or extend the maturity date of the 2021 RBL Facility, the 2021 RBL Facility will become current as of August 26, 2024 and the 2026 Notes will become current as of February 15, 2025. The failure to repay the 2021 RBL Facility or the 2026 Notes promptly following any such reclassification to current debt could result in a going concern qualification with respect to our annual audited financial statements.

We currently believe that our liquidity, capital resources and cash will be sufficient to conduct our business and operations and meet our obligations 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” in this Quarterly Report and Part I, Item 1A. “Risk Factors” in our 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

See Note 2—Debt in the Notes to Consolidated Financial Statements in Part I, Item 1. "Financial Statements" of this Quarterly Report for details regarding the current terms of the 2021 RBL Facility.

2022 ABL Facility

See Note 2—Debt in the Notes to Consolidated Financial Statements in Part I, Item 1. "Financial Statements" of this Quarterly Report for details.

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 and certain of its subsidiaries. C&J and C&J Management do not guarantee the 2026 Notes.

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 June 30, 2024.

Debt Repurchase Program

In February 2020, the board of directors (the "Board of Directors") adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and do not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any 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. We have also entered into gas transportation contracts in the Rockies to help reduce the price fluctuation exposure, however these do not qualify as hedges.

In addition, we also hedge to meet the hedging requirements of the 2021 RBL Facility. The 2021 RBL Facility requires us to maintain commodity hedges (other than three-way collars), with floor prices no less than 80% of the then prevailing market price at the time such hedging agreement is entered into, on minimum notional volumes of (i) at least 75% of our reasonably projected production of crude oil from our PDP reserves, for each full calendar month during the period from and including the first full calendar month following each April 1 and October 1 of each calendar year after the effective date of the 2021 RBL Facility through and including the 24th full calendar month following each such April 1 and October 1 and (ii) at least 50% of our reasonably projected production of crude oil from our PDP reserves, for each full calendar month during the period from and including the 25th full calendar month following each such Minimum Hedging Requirement Date through and including the 36th full calendar month following each such Minimum Hedging Requirement Date; provided, that in the case of each of the above clauses (i) and (ii), the notional volumes hedged are deemed reduced by the notional volumes of any short puts or other similar derivatives having the effect of exposing us to commodity price risk below the "floor."

In addition to minimum hedging requirements and other restrictions in respect of hedging described therein, the 2021 RBL Facility contains restrictions on our commodity hedging which prevent us from entering into hedging agreements (i) with a tenor exceeding 60 months or (ii) for notional volumes which (when aggregated with other commodity hedges then in effect other than basis differential swaps on volumes already hedged) exceed, as of the date such hedging agreement is executed, 90% of our reasonably projected production of crude oil from our PDP reserves, for each month following the date such hedging agreement is entered into, provided that such volume limitations do not apply to, among other things, short puts or long put options contracts that are not related to corresponding calls, collars, or swaps.

Our generally low-decline production base 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 Part I—Item 1A. "Risk Factors—Risks Related to Our Operations and Industry" in our Annual Report.

As of August 6, 2024, we had the following crude oil production and gas purchases hedges.

	Q3 2024	Q4 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Brent - Crude Oil production							
Swaps							
Hedged volume (bbls)	1,481,749	1,438,656	4,951,125	2,633,268	3,056,000	2,378,000	724,000
Weighted-average price ($/bbl)	$ 76.88	$ 76.93	$ 76.07	$ 71.76	$ 70.66	$ 68.36	$ 67.44
Sold Calls(1)							
Hedged volume (bbls)	92,000	92,000	296,127	1,251,500	318,500	—	—
Weighted-average price ($/bbl)	$ 105.00	$ 105.00	$ 88.69	$ 85.53	$ 80.03	$ —	$ —
Purchased Puts (net)(2)							
Hedged volume (bbls)	322,000	322,000	—	—	—	—	—
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ —	$ —	$ —	$ —	$ —
Purchased Puts (net)(2)							
Hedged volume (bbls)	—	—	296,127	1,251,500	318,500	—	—
Weighted-average price ($/bbl)	$ —	$ —	$ 60.00	$ 60.00	$ 65.00	$ —	$ —
Sold Puts (net)(2)							
Hedged volume (bbls)	46,000	46,000	—	—	—	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ —	$ —	$ —	$ —	$ —
NWPL - Natural Gas purchases(3)							
Swaps							
Hedged volume (mmbtu)	3,680,000	3,680,000	13,380,000	3,040,000	—	—	—
Weighted-average price ($/mmbtu)	$ 3.96	$ 3.96	$ 4.27	$ 4.26	$ —	$ —	$ —

(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.

(3) The term "NWPL" is defined as Northwest Rocky Mountain Pipeline.

(Losses) Gains on Derivatives

A summary of gains and losses on the derivatives included on the statements of operations is presented below:

	Three Months Ended			Six Months Ended	
	June 30, 2024	March 31, 2024	June 30, 2023	June 30, 2024	June 30, 2023
			(in thousands)		
Realized (losses) gains on commodity derivatives:					
Realized (losses) on oil sales derivatives	$ (9,801)	$ (4,682)	$ (1,770)	$ (14,483)	$ (9,208)
Realized (losses) gains on natural gas purchase derivatives	(9,314)	(4,412)	(10,754)	(13,726)	44,151
Total realized (losses) gains on derivatives	$ (19,115)	$ (9,094)	$ (12,524)	$ (28,209)	$ 34,943
Unrealized gains (losses) on commodity derivatives:					
Unrealized gains (losses) on oil sales derivatives	$ 3,957	$ (66,518)	$ 22,641	$ (62,561)	$ 68,578
Unrealized gains (losses) on natural gas purchase derivatives	6,672	(69)	(3,270)	6,603	(57,565)
Total unrealized gains (losses) on derivatives	$ 10,629	$ (66,587)	$ 19,371	$ (55,958)	$ 11,013
Total (losses) gains on derivatives	$ (8,486)	$ (75,681)	$ 6,847	$ (84,167)	$ 45,956

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

	Three Months Ended			Six Months Ended	
	June 30, 2024	March 31, 2024	June 30, 2023	June 30, 2024	June 30, 2023
Crude Oil (per bbl):					
Realized sales price, before the effects of derivative settlements	$ 78.18	$ 75.31	$ 70.68	$ 76.73	$ 72.62
Effects of derivative settlements	(4.60)	(2.17)	(0.81)	(3.38)	(2.18)
Realized sales price, after the effects of derivatives	$ 73.58	$ 73.14	$ 69.87	$ 73.35	$ 70.44
Purchased Natural Gas (per mmbtu):					
Purchase price, before the effects of derivative settlements	$ 2.26	$ 3.99	$ 3.44	$ 3.15	$ 11.86
Effects of derivative settlements	2.04	0.92	2.20	1.47	(4.64)
Purchase price, after the effects of derivatives settlements	$ 4.30	$ 4.91	$ 5.64	$ 4.62	$ 7.22

Cash Dividends

In the first quarter of 2024, our Board of Directors declared a fixed cash dividend of $0.12 per share, as well as a variable cash dividend of $0.14 per share which was based on the results of the fourth quarter of 2023, for a total of $0.26 per share, which we paid in March 2024. In April 2024, the Board of Directors approved a fixed cash dividend totaling $0.12 per share, which was paid in May 2024. In July 2024, the Board of Directors approved a fixed cash dividend of $0.12 per share and a variable cash dividend of $0.05 per share, based on the results for the six months ended June 30, 2024, for a total of $0.17per share, which is expected to be paid in August 2024.

The following table represents the regular fixed cash dividends on our common stock and variable dividends approved by our Board of Directors in 2024.

	First Quarter	Second Quarter	Year-to-Date
Fixed Dividends	$ 0.12	$ 0.12	$ 0.24
Variable Dividends[1]	—	0.05	0.05
Total	$ 0.12	$ 0.17	$ 0.29

(1) Variable dividends have been declared the quarter following the period of results. The table notes total dividends earned in each quarter. In July 2024, the Board of Directors approved a $0.05 variable dividend based on the results for the six months ended June 30, 2024.

Stock Repurchase Program

The Company did not repurchase any shares during the three and six months ended June 30, 2024. As of June 30, 2024, the Company had repurchased a total of 11.9 million shares, cumulatively, under the stock repurchase program for approximately $114 million in aggregate. According to the shareholder return model, the Company may allocate a portion of Adjusted Free Cash Flow, a non-GAAP measure, to opportunistic share repurchases.

As of June 30, 2024, the Company's remaining total share repurchase authority approved by the Board of Directors was $190 million. The Board of Directors' authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions or by other means, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors. The Board of Directors authorization has no expiration date.

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 the share repurchase program does 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.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Six Months Ended June 30,	
	2024	2023
	(in thousands)	
Net cash:		
Provided by operating activities	$ 98,164	$ 64,319
Used in investing activities	(61,147)	(58,421)
Used in financing activities	(35,164)	(43,582)
Net (decrease) in cash and cash equivalents	$ 1,853	$ (37,684)

Operating Activities

Cash provided by operating activities increased for the six months ended June 30, 2024 by approximately $34 million when compared to the six months ended June 30, 2023. The increase was primarily related to a decrease in lease operating expenses (largely fuel gas purchases), an increase in unhedged revenue, and an increase in the change in net working capital, and lower general and administrative expenses (from lower payroll costs) and lower executive transition costs, partially offset by an increase in derivatives settlements paid and an increase in taxes, other than income taxes.

Investing Activities

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

	Six Months Ended June 30,	
	2024	2023
	(in thousands)	
Capital expenditures:		
Capital expenditures	$ (59,261)	$ (42,528)
Changes in capital expenditures accruals	4,147	(8,564)
Acquisitions, net of cash received	(6,033)	(7,329)
Net cash used in investing activities	$ (61,147)	$ (58,421)

Cash used in investing activities increased $3 million for the six months ended June 30, 2024 when compared to the same period in 2023, primarily due to higher capital expenditures as we drilled more wells in the first half of 2024 versus the first half of 2023 as well as the capital expenditures related to our non-operated interest in four horizontal wells in Utah.

Financing Activities

Cash used in financing activities decreased approximately $10 million for the six months ended June 30, 2024 when compared to the six months ended June 30, 2023 primarily due to decreased dividends paid, partially offset by decreased borrowings under the 2021 RBL credit facility.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2023 to June 30, 2024 are discussed below.

	June 30, 2024	December 31, 2023
	(in thousands)	
Cash and cash equivalents	$ 6,688	$ 4,835
Accounts receivable, net	$ 82,017	$ 86,918
Derivative instruments assets - current and long-term	$ —	$ 10,751
Other current assets	$ 38,784	$ 43,759
Property, plant & equipment, net	$ 1,349,593	$ 1,406,612
Deferred income taxes asset - long-term	$ 45,915	$ 30,308
Other noncurrent assets	$ 9,912	$ 10,975
Accounts payable and accrued expenses	$ 168,426	$ 213,401
Derivative instruments liabilities - current and long-term	$ 55,946	$ 10,740
Long-term debt	$ 433,656	$ 427,993
Deferred income taxes liability - long-term	$ —	$ 2,344
Asset retirement obligations - long-term	$ 178,980	$ 176,578
Other noncurrent liabilities	$ 22,941	$ 5,126
Stockholders' equity	$ 672,960	$ 757,976

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

The $5 million decrease in accounts receivable was primarily due to decreased oil and gas sales between the two ending periods.

The $5 million decrease in other current assets was primarily due to prepaid expense amortization.

The $57 million decrease in property, plant and equipment was primarily due to year-to-date changes in accumulated depreciation of $79 million and $44 million in impairment, offset by $59 million in capital investments and $6 million in acquisitions.

The $16 million increase in net deferred income taxes assets - long term, which includes the deferred tax liability, was primarily due to the tax effect of the year-to-date book loss.

The $45 million decrease in accounts payable and accrued expenses includes decreased fuel gas purchases (based on lower fuel gas price) since year end, decreased for greenhouse gas liability and payments in the first half of 2024 for royalties and annual incentive compensation, offset by an increase in the capital spend accrual as well as a small increase in taxes other than income taxes.

The $56 million increase in net derivative liability, which includes the derivative asset, is due to change in the derivative values and positions at the end of each period. 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 $6 million increase in long-term debt largely reflected year-to-date borrowings, net of repayments, on our 2021 RBL Facility related to typical first quarter working capital needs largely paid down in the second quarter.

The $2 million decrease in deferred income taxes liability - long-term is due to the year-to-date state NOL that was generated.

The $2 million increase in the long-term portion of the asset retirement obligations from $177 million at

December 31, 2023 to $178 million at June 30, 2024 was due to $6 million of accretion expense and $1 million in liabilities incurred, largely offset by $5 million of liabilities settled during the period.

The $18 million increase in other noncurrent liabilities is primarily due to the obligations for greenhouse gas allowances incurred in the first half of 2024 due in over one year.

The $85 million decrease in stockholders' equity was due to $34 million of common stock dividends, $49 million in net loss, and $5 million of shares withheld for payment of taxes on equity awards, partially offset by $3 million of stock-based compensation.

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, false claims, 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 June 30, 2024 and December 31, 2023. 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 June 30, 2024, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matters

In November 2020, a putative securities class action (the "Securities Class Action") was filed in the United States District Court for the Northern District of Texas, claiming that Berry Corp. and certain of its current and former directors and officers violated the Securities Act of 1933 and the Exchange Act of 1934 by allegedly making false and misleading statements between the IPO and November 3, 2020, and in the IPO offering materials, about the Company's permits and permitting processes.

While the motion for class certification was still pending before the court, the parties reached an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. Following notice to the class and an opt-out and objection process, the Court granted final approval of the settlement on February 6, 2024, and terminated the case. The Defendants continue to maintain that the claims were without merit and admitted no liability in connection with the settlement.

While the Securities Class Action is now concluded, certain related shareholder derivative actions remain pending. 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 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 further developments in the Securities Class Action.

The settlement of the Securities Class Action did not resolve the Shareholder Derivative Actions, which remain pending. 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 June 30, 2024:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
			(in thousands)		
Debt obligations:					
RBL Facility	$ 36,000	$ —	$ 36,000	$ —	$ —
2026 Notes	400,000	—	400,000	—	—
Interest[1]	45,500	28,000	17,500	—	—
Deferred acquisition payable[2]	20,000	20,000	—	—	—
Other:					
Leases	7,267	2,780	3,809	678	—
Asset retirement obligations[3]	198,980	20,000	—	—	178,980
Off-Balance Sheet arrangements:[4]					
Transportation contracts[5]	75,520	10,972	16,952	16,165	31,431
GHG compliance purchase contracts[6]	22,279	17,695	4,584	—	—
Other purchase obligations[7]	17,100	17,100	—	—	—
Total contractual obligations	$ 822,646	$ 116,547	$ 478,845	$ 16,843	$ 210,411

(1) Represents interest on the 2026 Notes computed at 7% through contractual maturity in 2026.

(2) The remaining payable of $20 million for the acquisition of Macpherson Energy, as of June 30, 2024. The amount was paid in July 2024.

(3) Represents the estimated future asset retirement obligations on a discounted basis. We do not show the long-term asset retirement obligations by year as we are not able to precisely predict the timing of these amounts. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgements that are subject to revisions based on numerous factors, including the rate of inflation, changing technology, and changes to federal, state and local laws and regulations. See Note 1—Basis of Presentation in the notes to consolidated financial statements in Part II—Item 8. “Financial Statements and Supplementary

Data" in our Annual Report for more information.

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

(5) 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.

(6) We have entered into contracts to purchase GHG compliance instruments totaling $22 million, of which $7 million will be delivered and paid in the fourth quarter 2024 and the remaining $15 million of these instruments will be delivered and paid in 2025.

(7) As of June 30, 2024, we have a total drilling commitment in California of $17.1 million. We are required to drill 57 wells consisting of 28 wells by December 2024 and the remaining 29 wells by June 2025.

Critical Accounting Policies and Estimates

There have been no significant changes to our critical accounting policies and estimates from those disclosed in our Annual Report. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" in our 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. 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. 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. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. 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 in Part I, Item 1A. "Risk Factors" in our 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, GHGs or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- our ability to refinance or pay, when due, the principal of, interest or other amounts due in respect of our indebtedness, including our 2026 Notes and our 2021 RBL Facility;
- inflation levels and government efforts to reduce inflation, including related interest rate determinations;
- overall domestic and global political and economic trends, geopolitical risks and general economic and industry conditions, such as inflation, high interest rates, increased volatility in financial and credit markets, global supply chain disruptions, government interventions into the financial markets and economy and volatility related to recent and upcoming elections in the United States and other major economies;

- 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 ongoing conflict in the Middle East, or a prolonged recession, among other factors;
- volatility of oil, natural gas and NGL prices, including as a result of political instability, armed conflicts 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;
- risks related to our public statements with respect to sustainability matters that may be subject to heightened scrutiny from the public and governmental authorities related to the risk of potential "greenwashing";
- 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;
- competition and consolidation in the oil and gas E&P industry;
- 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 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;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- risks related to acquisitions, including the risk that we may fail to successfully integrate the assets into our operations, identify risks or liabilities associated with the acquired entity, its operations or assets, or realize any anticipated benefits or growth;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines, regulatory changes, permitting delays or other factors;
- 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 statements, 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 June 30, 2024, there have been no material changes in the information required to be provided under Item 305 of Regulation S-K included in Part II, Item 7A. *"Quantitative and Qualitative Disclosures About Market Risk"* in our 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 and emission allowances required by California's cap-and-trade program 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 June 30, 2024, the fair value of our hedge positions was a net liability of approximately $56 million. A 10% increase in the oil and natural gas index prices above the June 30, 2024 prices would result in a net liability of approximately $135 million; conversely, a 10% decrease in the oil and natural gas index prices below the June 30, 2024 prices would result in a net asset of approximately $27 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. "Financial Statements" of this Quarterly Report.

At June 30, 2024, the fair value of our emission allowances required by California's cap-and-trade program was $9 million. A 10% increase or decrease in the market price would result in a change in expense by approximately $1 million.

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 June 30, 2024.

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 second quarter of 2024 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

In November 2020, a putative securities class action (the "Securities Class Action") was filed in the United States District Court for the Northern District of Texas, claiming that Berry Corp. and certain of its current and former directors and officers violated the Securities Act of 1933 and the Exchange Act of 1934 by allegedly making false and misleading statements between the IPO and November 3, 2020, and in the IPO offering materials, about the Company's permits and permitting processes.

While the motion for class certification was still pending before the court, the parties reached an agreement-in-principle to settle all claims in the Securities Class Action for an aggregate sum of $2.5 million. Following notice to the class and an opt-out and objection process, the Court granted final approval of the settlement on February 6, 2024, and terminated the case. The Defendants continue to maintain that the claims were without merit and admitted no liability in connection with the settlement.

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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—Commitments and Contingencies in the notes to condensed consolidated financial statements in Part I, Item 1. “Financial Statements” in this Quarterly Report and Note 5—Commitments and Contingencies in the notes to consolidated financial statements in Part II, Item 8. “Financial Statements and Supplementary Data” in our 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 Annual Report.

The recent definitive implementation of SB 1137 to restrict the production of oil and gas in certain setback areas is expected to negatively impact our reserves and could result in decreased demand for fossil fuels within the states where we operate.

In September 2022, the Governor of California signed into law 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, effective January 1, 2023. On January 6, 2023, CalGEM’s emergency regulations to support implementation of SB 1137 were approved by the Office of Administrative Law and final regulations were published. See Part II, Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Regulatory Matters—*Setbacks—SB 1137*” in this Quarterly Report. SB 1137 was stayed pending a vote of the California General Election in November 2024, however, in June 2024, the ballot proposal was withdrawn with the proposal’s sponsors instead indicating a view to challenging SB 1137 in court and the provisions of SB 1137 are effective immediately.

As a result of the setbacks established by SB 1137, we recorded a non-cash pre-tax asset impairment charge of $44 million, $33 million after-tax) on unproved oil and gas properties in certain California locations during the second quarter of 2024. The impairment represents approximately 2% of our total oil and natural gas properties. See Note 10—Oil and Natural Gas Properties to the Financial Statements.

In addition to the permitting requirements, by January 1, 2025, all wells and facilities within a setback must be in compliance with specific health, safety and environmental requirements pursuant to SB 1137 with leak detection and response plans developed and submitted to CalGEM for agency approval. CalGEM must approve these plans by January 1, 2026 and, beginning on January 1, 2027, operators are required to suspend operations within setback areas unless they have a CalGEM-approved leak detection and response plan that has been fully implemented. This plan must be updated every five years, and operators must annually report on implementation of these plans as well as the results of baseline water quality testing. The majority of our production is in rural areas in the San Joaquin basin and is unlikely to be affected by SB 1137. Approximately 15% of our production for the six months ended June 30, 2024 was within setback zones subject to SB 1137 and subject to these requirements. We do not expect this law to result in any material change to our overall existing proved developed producing reserves or current production rates. However, we cannot predict CalGEM’s timeline for approving these plans or whether CalGEM will require more stringent mitigation in connection with final approval of such plans, or whether circumstances may arise in the future that could adversely impact production within setback zones. Additionally, failure to comply with the requirements of SB 1137 may result in enforcement action and the imposition of substantial fines and penalties.

We may not be successful in refinancing, repaying or extending the maturity of our 2026 Notes or our 2021 RBL Facility, and any such refinancing may not be obtainable on terms favorable to us. If we are not able to refinance the 2026 Notes or extend the maturity date of the 2021 RBL Facility, the 2021 RBL Facility and the 2026 Notes will be classified as current debt as of August 26, 2024 and February 15, 2025, respectively.

The 2021 RBL Facility matures on August 26, 2025 and the 2026 Notes mature on February 15, 2026. We are currently evaluating prospective financing arrangements to refinance our 2026 Notes and extend the maturity date of the 2021 RBL Facility. We may not be successful in refinancing, repaying or extending the maturity of our 2026 Notes or our 2021 RBL Facility, and any such refinancing may not be obtainable on terms favorable to us. If we are not able to refinance the 2026 Notes or extend the maturity date of the 2021 RBL Facility, the 2021 RBL Facility and the 2026 Notes will be classified as current debt as of August 26, 2024 and February 15, 2025, respectively. The failure to repay the 2021 RBL Facility or the 2026 Notes promptly following any such reclassification to current debt could result in a going concern qualification with respect to our annual audited financial statements.

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

Stock Repurchase Program

The Company did not repurchase any shares during the three and six months ended June 30, 2024. As of June 30, 2024, the Company had repurchased a total of 11.9 million shares, cumulatively, under the stock repurchase program for approximately $114 million in aggregate, which is 16% of outstanding shares as of June 30, 2024. According to the shareholder return model, the Company may allocate a portion of Adjusted Free Cash Flow, a non-GAAP measure, to opportunistic share repurchases.

As of June 30, 2024, the Company's remaining total share repurchase authority approved by the Board of Directors was $190 million. The Board of Directors' authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions or by other means, subject to market conditions and other factors, up to the aggregate amount authorized by the Board of Directors. The Board of Directors authorization has no expiration date.

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 the share repurchase program does 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 June 30, 2024, 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 to the Company's Current Report on 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 to the Company's Current Report on 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 to the Company's Current Report on Form 8-K filed July 30, 2018)
10.1*	Third Amendment to Revolving Loan and Security Agreement and Amendment to Other Loan Documents, dated as of June 25, 2024, by and among C&J Well Services, LLC, as a borrower, CJ Berry Well Services Management, LLC, as a borrower, and Tri Counties Bank, as lender
10.2*	Letter regarding amendment to Section 9.18 of Credit Agreement, dated July 30, 2024, from JPMorgan Chase Bank, N.A. to Berry Petroleum Company, LLC and agreed and acknowledged by Berry Petroleum Company, LLC, Berry Corporation (bry), the other guarantors party thereto and the lenders and issuing banks party thereto
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*" is a non-GAAP financial measure which is defined (i) through December 31, 2023, as cash flow from operations less regular fixed dividends and maintenance capital and (ii) beginning January 1, 2024, as cash flow from operations, less regular fixed dividends and capital expenditures. Adjusted Free Cash Flow for prior periods has not been retroactively adjusted for the updated definition.

"*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:	August 9, 2024	*/s/* Fernando Araujo
		Fernando Araujo Chief Executive Officer (Principal Executive Officer)
Date:	August 9, 2024	*/s/* Michael S. Helm
		Michael S. Helm Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial Officer and Principal Accounting Officer)

THIRD AMENDMENT TO REVOLVING LOAN AND SECURITY AGREEMENT AND AMENDMENT TO OTHER LOAN DOCUMENTS

THIS THIRD AMENDMENT TO REVOLVING LOAN AND SECURITY AGREEMENT AND OTHER LOAN DOCUMENTS (this "Amendment") is entered into as of June 25, 2024, by and among C&J WELL SERVICES, LLC, a Delaware limited liability company ("C&J Well Services"), and CJ BERRY WELL SERVICES MANAGEMENT, LLC, a Delaware limited liability company ("CJ Berry Well Services Management", and together with C&J Well Services, at times hereinafter referred to individually and collectively as "Borrower"), on the one hand, and TRI COUNTIES BANK, a California banking corporation ("Lender"), on the other hand.

RECITALS

A. Lender previously extended a revolving line of credit to Borrower in the original, maximum principal amount of Fifteen Million and No/100 Dollars ($15,000,000.00) (the "Loan"), pursuant to, inter alia, that certain Revolving Loan and Security Agreement dated as of August 9, 2022, executed by and among Borrower and Lender (together with the First Amendment (as herein defined), the Second Amendment (as herein defined), and any and all other amendments and extensions thereto or modifications thereof, the "Loan Agreement"). Any and all capitalized terms used but not expressly defined herein shall have the meanings ascribed to them in the Loan Agreement.

B. The Loan is evidenced, in part, by that certain Promissory Note dated August 9, 2022, in the principal amount of Fifteen Million and No/100 Dollars ($15,000,000.00), executed by Borrower in favor of Lender (together with any and all amendments and extensions thereto or modifications thereof, the "Note").

C. The Loan is secured by the Collateral (as that term is defined in the Loan Agreement) described in the Loan Agreement. Lender's security interest in the Collateral described in the Loan Agreement was and is perfected under applicable law.

D. The Loan Agreement was previously amended pursuant to that certain Amendment to Revolving Loan and Security Agreement dated as of March 14, 2023, between Lender and Borrower (the "First Amendment"). Reference is made to the First Amendment for the particulars thereof.

E. The Loan Agreement was also previously amended pursuant to that certain Second Amendment to Revolving Loan and Security Agreement and Amendment to Other Loan Documents dated as of November 15, 2023, between Lender and Borrower (the "Second Amendment"). Reference is made to the Second Amendment for the particulars thereof.

F. The Loan Agreement, the Note, and all other assignments, agreements, instruments and other documents executed by Borrower in connection with the Loan, together with any and all amendments (including the First Amendment and Second Amendment), modifications, restatements, renewals, and replacements thereof, shall at times hereinafter be referred to collectively as the "Loan Documents."

G. Borrower and Lender desire to further amend the Loan Agreement and certain of the other Loan Documents on the terms and conditions set forth in this Amendment.

AGREEMENT

NOW, THEREFORE, for valuable consideration and the mutual promises of the parties hereto, said parties do hereby acknowledge and agree as follows:

1. Recitals.

The recitals are incorporated herein by this reference as are all exhibits. Borrower, and each of them, agree and acknowledge that the factual information recited above is true and correct.

2. Borrower's Acknowledgment as to Obligations.

A. Borrower, and each of them, acknowledge, confirm and agree that as of June 21, 2024, there are no outstanding Revolving Advances under the Note, and the aggregate stated amount of issued and outstanding Letters of Credit is $2,650,000.00.

B. Borrower, and each of them, specifically acknowledge and confirm that they do not have any valid offset or defense to the obligations, indebtedness and liability under the Loan Documents.

3. Reaffirmation of Obligations.

This Amendment is, in part, a reaffirmation of the obligations, indebtedness and liability of Borrower, and each of them, to Lender as evidenced by the Loan Documents. Therefore, Borrower, and each of them, acknowledge and agree that, except as specified herein, all of the terms and conditions of the Loan Documents are and shall remain in full force and effect, without waiver or modification of any kind whatsoever, and are ratified and confirmed in all respects.

4. Amendments to Loan Agreement and Other Loan Documents.

Subject to Borrower's satisfaction of any and all conditions precedent to the effectiveness of this Amendment (including, without limitation, the conditions set forth in Section 8, below), the Loan Documents are hereby modified as follows:

A. In Section 1.1 of the Loan Agreement, the definition of "Maturity Date" is hereby amended in its entirety to read as follows:

" 'Maturity Date' means June 5, 2027."

All references in the Loan Agreement, the Note, and any and all other Loan Documents to the Maturity Date of the line of credit evidenced by the Loan Agreement and the Note shall hereafter mean and refer to "June 5, 2027", at which time the entire unpaid principal balance of the Loan, all accrued and unpaid interest thereon, and all other unpaid sums owing by Borrower under the Loan Documents shall be due and payable to Lender.

5. Amendment as a Loan Document.

From and after the effective date of this Amendment, this Amendment and any other documents and instruments executed in connection herewith shall each constitute one of the "Loan Documents."

6. Effective Date of Amendment.

This Amendment and the amendments provided for herein shall be effective upon the timely and complete satisfaction of each and all of the conditions precedent set forth in Section 8 of this Amendment.

7. Borrower's Representations and Warranties.

Borrower, and each of them, hereby represent and warrant to Lender and covenant and agree with Lender as follows:

A. Borrower, and each of them, have full legal right, power and authority to enter into and perform this Amendment. The execution and delivery of this Amendment by Borrower, and each of them, and the consummation by Borrower, and each of them, of the transactions contemplated hereby have been duly authorized by all necessary action by or on behalf of each of the Borrower. This Amendment is a valid and binding obligation of Borrower, and each of them, enforceable against Borrower, and each of them, in accordance with its terms.

B. Neither the execution and delivery of this Amendment by Borrower, or any of them, nor the consummation by Borrower, or any of them, of the transactions contemplated hereby, conflicts with or constitutes a violation or a default under any law or regulation applicable to Borrower, or any of them, or any contract, commitment, agreement, arrangement or restriction of any kind to which Borrower, or any of them, is a party, by which Borrower, or any of them, respectively, is bound or to which any of the Borrower's, or any of their, property or assets is subject.

C. There are no actions, suits or proceedings pending, or to the best knowledge of Borrower, or any of them, threatened against or affecting Borrower, or any of them, respectively, in relation to their obligations to Lender or involving the validity and enforceability of this Amendment, the Loan Agreement, or any of the other Loan Documents, as applicable, or the priority of any liens given by Borrower, or any of them, to Lender in accordance with the Loan Agreement and the other Loan Documents, at law or in equity, or before or by any governmental agency, or which could have a material adverse effect on the financial condition, operations, properties, assets, liabilities or earnings of Borrower, or any of them, or the ability of Borrower, or any of them, to perform their respective obligations to Lender.

D. Borrower, and each of them, hereby reaffirm and confirm that the representations and warranties of Borrower, and each of them, as applicable, contained in the Loan Documents are true, correct and complete in all material respects as of the date of this Amendment.

E. Borrower, and each of them, are in full and complete compliance with the terms, covenants, provisions and conditions of the Note, the Loan Agreement, and the other Loan Documents.

All covenants, representations and warranties of Borrower, and each of them, herein are incorporated by reference and hereby made a part of the Loan Agreement.

8. Conditions Precedent to Effectiveness of Amendment.

The effectiveness of this Amendment is expressly conditioned upon the Borrower having, at their sole expense, deposited or caused to be deposited with Lender by no later than June 28, 2024, all of the following items, documents, certificates and other instruments, in form and content satisfactory to Lender and its counsel, in their sole and absolute discretion, and suitable for filing or recording as required:

A. This Amendment, fully executed by each Borrower;

B. Such additional information, assignments, agreements, certificates, reports, approvals, instruments, documents, subordination agreements, financing statements, consents and opinions as Lender may request, in its sole and absolute opinion and judgment, in connection with this Amendment and/or any of the matters which are the subject of this Amendment; and

C. Payment of the fees and costs of Lender in connection with the preparation, negotiation, administration and execution of this Amendment including, but not limited to, attorneys' fees and other costs and fees of other professionals retained by Lender.

9. Miscellaneous.

A. Section headings used in this Amendment are for convenience only and shall not affect the construction of this Amendment.

B. This Amendment may be executed in one or more counterparts but all of the counterparts shall constitute one agreement; provided, however, this Amendment shall not be effective and enforceable unless and until it is executed by all parties hereto.

C. This Amendment and the other documents and instruments executed in connection therewith constitute the product of the negotiation of the parties hereto and the enforcement hereof shall be interpreted in a neutral manner, and not more strongly for or against any party based upon the source of the draftsmanship hereof.

D. This Amendment shall be binding upon and inure to the benefit of Lender, Borrower, and each of them, and their respective successors and assigns, except that no Borrower shall assign their rights hereunder or any interest therein without the prior written consent of Lender.

E. This Amendment is not a novation, nor, except as expressly provided in this Amendment, is it to be construed as a release or modification of any of the terms, conditions, warranties, waivers or rights set forth in the Loan Documents. Nothing contained in this Amendment shall be deemed to constitute a waiver by Lender of any required performance by Borrower, and each of them, of any Event of Default or default heretofore or hereafter occurring under or in connection with the other Loan Documents. In the event there is a conflict in any term, condition or provision of this Amendment, on the one hand, and the Note, the Loan Agreement, or any of the other Loan Documents, on the other hand, the terms, conditions and provisions of this Amendment are to control.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, Borrower has executed this Amendment as of the date set forth in the heading to this Amendment.

BORROWER:

C&J WELL SERVICES, LLC,
a Delaware limited liability company

By: /s/ Michael Helm
Name: Michael Helm
Title: CFO

CJ BERRY WELL SERVICES MANAGEMENT, LLC,
a Delaware limited liability company

By: /s/ Michael Helm
Name: Michael Helm
Title: CFO

IN WITNESS WHEREOF, Lender has executed this Amendment as of the date set forth in the heading to this Amendment.

LENDER:

TRI COUNTIES BANK,
a California banking corporation

By: /s/ Jennifer Meadors
Name: Jennifer Meadors
Its: Vice President

Exhibit 10.2

J.P.Morgan

July 30, 2024

Berry Petroleum Company, LLC
16000 N. Dallas Pkwy., Suite 500
Dallas, TX 75248
Attn: Michael Helm

Re: Amendment to Section 9.18 of Credit Agreement

Ladies and Gentlemen:

Reference is hereby made to that certain Credit Agreement, dated as of August 26, 2021 (as amended, restated, amended and restated, supplemented or otherwise modified prior to the date hereof, the "Credit Agreement"), by and among Berry Petroleum Company, LLC, a Delaware limited liability company (the "Borrower"), Berry Corporation (bry), a Delaware corporation ("Parent"), each of the lenders from time to time party thereto (the "Lenders"), and JPMorgan Chase Bank, N.A., as administrative agent (in such capacity, the "Administrative Agent"). Capitalized terms used herein without definition shall have the meanings given to them in the Credit Agreement.

The Borrower, Parent, the other Loan Parties party hereto, the Administrative Agent and the Required Lenders desire to enter into this letter agreement (this "Letter Agreement") with respect to the Credit Agreement, and, in consideration of the mutual agreements herein contained and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. Amendment to Section 9.18 of Credit Agreement. In reliance on the representations and warranties of the Loan Parties contained herein, and subject to the receipt by the Administrative Agent of executed counterparts of this Letter Agreement from the Loan Parties and the Required Lenders, Section 9.18(a) of the Credit Agreement is hereby amended, effective as of the date hereof, by replacing the reference therein to "with a tenor not to exceed 48 months" with a reference to "with a tenor not to exceed 60 months".

2. Confirmation and Effect. The provisions of the Credit Agreement (as amended by this Letter Agreement) shall remain in full force and effect in accordance with their terms following the effectiveness of this Letter Agreement, and this Letter Agreement shall not constitute a waiver of any provision of the Credit Agreement or any other Loan Document, except as expressly provided for herein. Each reference in the Credit Agreement to "this Agreement", "hereunder", "hereof", "herein", or words of like import shall mean and be a reference to the Credit Agreement as amended hereby, and each reference to the Credit Agreement in any other document, instrument or agreement executed and/or delivered in connection with the Credit Agreement shall mean and be a reference to the Credit Agreement as amended hereby.

3. Representations and Warranties. To induce the Administrative Agent and the Required Lenders to enter into this Letter Agreement, each of the Loan Parties hereby expressly (i) acknowledges the terms of this Letter Agreement, (ii) ratifies and affirms its obligations under the Loan Documents to which it is a party, (iii) acknowledges and renews its continued liability under the Loan Documents to which it is a party, (iv) agrees, with respect to Parent, that its guarantee under Article XIII of the Credit Agreement

remains in full force and effect with respect to the Guaranteed Obligations as amended hereby, (v) agrees, with respect to the Guarantors other than Parent, that the Guaranty Agreement remains in full force and effect with respect to the Obligations as amended hereby, and (vi) represents and warrants to the Lenders and the Administrative Agent that each representation and warranty of such Loan Party contained in the Credit Agreement and the other Loan Documents to which it is a party is true and correct in all material respects as of the date hereof, after giving effect to this Letter Agreement, except (A) to the extent any such representations and warranties are expressly limited to an earlier date, in which case, on and as of the date hereof, such representations and warranties shall continue to be true and correct in all material respects as of such specified earlier date, and (B) to the extent that any such representation and warranty is expressly qualified by materiality or by reference to Material Adverse Effect, such representation and warranty (as so qualified) shall continue to be true and correct in all respects.

4. Miscellaneous.

(a) The Borrower agrees to pay or reimburse the Administrative Agent for all of its reasonable and documented out-of-pocket costs and expenses incurred in connection with this Letter Agreement, any other documents prepared in connection herewith and the transactions contemplated hereby, including, without limitation, the reasonable and documented fees and disbursements of counsel to the Administrative Agent, in each case, to the extent so provided in Section 12.03 of the Credit Agreement.

(b) This Letter Agreement may be executed in counterparts, and all parties need not execute the same counterpart; however, no party shall be bound by this Letter Agreement until a counterpart hereof has been executed by each Loan Party, the Administrative Agent and the Required Lenders.

(c) Delivery of a counterpart of this Letter Agreement by facsimile or other electronic transmission (e.g., pdf) shall be effective as originals.

(d) THIS LETTER AGREEMENT REPRESENTS THE FINAL AGREEMENT AMONG THE PARTIES REGARDING THE MATTERS SET FORTH HEREIN AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS AMONG THE PARTIES.

(e) This Letter Agreement constitutes a Loan Document under and as defined in the Credit Agreement.

(f) This Letter Agreement shall be governed by, and construed in accordance with, the laws of the State of New York.

If you are in agreement with the foregoing, please execute this Letter Agreement in the space indicated below and return an executed counterpart of this Letter Agreement to Paul Hastings LLP., counsel to the Administrative Agent, at 2001 Ross Avenue, Suite #700-168, Dallas, TX 75201 Attn: Christina Ta (email: christinata@paulhastings.com).

[Signature Pages to Follow]

Very truly yours,

JPMORGAN CHASE BANK, N.A.,
as Administrative Agent and a Lender

By: /s/ Michael A Harvey______
Name: Michael A. Harvey
Title: Authorized Officer

[Signature Page to Letter Agreement – Berry Petroleum Company, LLC]

Agreed and Acknowledged:

BORROWER: BERRY PETROLEUM COMPANY, LLC

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

PARENT AND A GUARANTOR: BERRY CORPORATION (BRY)

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

OTHER GUARANTORS: MACPHERSON ENERGY, LLC

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON OIL COMPANY LLC

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON ROUND MOUNTAIN HOLDINGS, LLC

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON POWER COMPANY, LLC

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON POWER COMPANY, L.P.

By: MACPHERSON POWER COMPANY, LLC, its general partner

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON OPERATING COMPANY, LLC

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON OPERATING COMPANY, L.P.

By: MACPHERSON OPERATING COMPANY, LLC, its general partner

By: /s/ Michael Helm
Name: Michael Helm
Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON POWER COMMERCIAL SERVICES, LLC

By: /s/ Michael Helm

Name: Michael Helm

Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON POWER COMMERCIAL SERVICES, L.P.

By: MACPHERSON POWER COMMERCIAL SERVICES, LLC, its general partner

By: /s/ Michael Helm
Name: Michael Helm

Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON LAND COMPANY, LLC

By: /s/ Michael Helm
Name: Michael Helm

Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON LAND COMPANY, L.P.

By: MACPHERSON LAND COMPANY, LLC, its general partner

By: /s/ Michael Helm
Name: Michael Helm

Title: Vice President, Chief Financial Officer and Chief Accounting Officer

MACPHERSON GREEN POWER COMPANY, LLC

By: /s/ Michael Helm
Name: Michael Helm

Title: Vice President, Chief Financial Officer and Chief Accounting Officer

LENDERS: **KEYBANK NATIONAL ASSOCIATION**, as a Lender and Issuing Bank

By: /s/ David M. Bornstein
Name: David M. Bornstein
Title: Senior Vice President

TRI COUNTIES BANK, as a Lender

By: /s/ Jennifer Meadors
Name: Jennifer Meadors
Title: VP, Senior Portfolio Manager

[Signature Page to Letter Agreement – Berry Petroleum Company, LLC]

CAPITAL ONE, NATIONAL ASSOCIATION, as a Lender

By: /s/ Chistopher Kuna
Name: Chistopher Kuna
Title: Senior Director

[Signature Page to Letter Agreement – Berry Petroleum Company, LLC]

GOLDMAN SACHS LENDING PARTNERS LLC, as a Lender

By: /s/ Sarah Kiernan
Name: Sarah Kiernan
Title: Authorized Signatory

[Signature Page to Letter Agreement – Berry Petroleum Company, LLC]

MACQUARIE BANK LIMITED, as a Lender

By: /s/ Bruce See
Name: Bruce See
Title: Division Director

By: /s/ Chris Horne
Name: Chris Horne
Title: Division Director

Signed in Sydney under MBL POA No. 3322, expiring 31 January 2025

CATHAY BANK, as a Lender

By: /s/ Dale T Wilson
Name: Dale T Wilson
Title: Senior Vice President

[Signature Page to Letter Agreement – Berry Petroleum Company, LLC]

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: August 9, 2024

/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: August 9, 2024

/s/ Michael 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 June 30, 2024, as filed with the Securities and Exchange Commission on August 9, 2024 (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:	August 9, 2024	/s/ Fernando Araujo Fernando Araujo Chief Executive Officer
Date:	August 9, 2024	/s/ Michael 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.