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, 2022

OR

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

For the transition period from_______________ to _______________

Commission file number 001-38606

Berry Corporation (bry)

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒	Non-accelerated filer ☐	Smaller reporting company ☐
Emerging Growth Company ☒			

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Shares of common stock outstanding as of July 31, 2022 78,760,354

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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, 2022	December 31, 2021
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 52,495	$ 15,283
Accounts receivable, net of allowance for doubtful accounts of $866 at June 30, 2022 and $866 at December 31, 2021	117,281	86,269
Other current assets	35,122	45,946
Total current assets	204,898	147,498
Noncurrent assets:		
Oil and natural gas properties	1,618,258	1,537,894
Accumulated depletion and amortization	(402,640)	(340,328)
Total oil and natural gas properties, net	1,215,618	1,197,566
Other property and equipment	144,917	140,710
Accumulated depreciation	(46,608)	(36,927)
Total other property and equipment, net	98,309	103,783
Derivative instruments	—	1,070
Other noncurrent assets	11,560	6,562
Total assets	$ 1,530,385	$ 1,456,479
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 160,683	$ 157,524
Derivative instruments	101,063	29,625
Total current liabilities	261,746	187,149
Noncurrent liabilities:		
Long-term debt	395,135	394,566
Derivative instruments	59,604	18,577
Deferred income taxes	1,322	1,831
Asset retirement obligations	139,956	143,926
Other noncurrent liabilities	31,853	17,782
Commitments and Contingencies - Note 4		
Stockholders' Equity:		
Common stock ($0.001 par value; 750,000,000 shares authorized; 86,343,622 and 85,590,417 shares issued; and 78,760,354 and 80,007,149 shares outstanding, at June 30, 2022 and December 31, 2021, respectively)	86	86
Additional paid-in-capital	896,808	912,471
Treasury stock, at cost (7,583,268 and 5,583,268 shares at June 30, 2022 and December 31, 2021, respectively)	(75,196)	(52,436)
Retained deficit	(180,929)	(167,473)
Total stockholders' equity	640,769	692,648
Total liabilities and stockholders' equity	$ 1,530,385	$ 1,456,479

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,	
	2022	2021	2022	2021
	(in thousands, except per share amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 240,071	$ 147,775	$ 450,422	$ 283,040
Services revenue	46,178	—	86,014	—
Electricity sales	7,419	6,888	12,838	16,957
Losses on oil and gas sales derivatives	(40,658)	(55,653)	(202,516)	(109,157)
Marketing revenues	—	121	289	2,355
Other revenues	120	118	165	255
Total revenues and other	253,130	99,249	347,212	193,450
Expenses and other:				
Lease operating expenses	72,455	45,543	135,579	107,827
Costs of services	36,709	—	70,181	—
Electricity generation expenses	6,122	4,712	10,585	12,360
Transportation expenses	1,108	1,757	2,266	3,333
Marketing expenses	—	44	299	2,271
General and administrative expenses	23,183	16,065	46,125	33,135
Depreciation, depletion, and amortization	38,055	35,850	77,832	69,690
Taxes, other than income taxes	11,214	11,603	17,819	21,160
Losses (gains) on natural gas purchase derivatives	10,661	(11,639)	(18,393)	(39,369)
Other operating expenses	353	42	4,122	841
Total expenses and other	199,860	103,977	346,415	211,248
Other (expenses) income:				
Interest expense	(7,729)	(8,217)	(15,404)	(16,702)
Other, net	(42)	(8)	(55)	(151)
Total other (expenses) income	(7,771)	(8,225)	(15,459)	(16,853)
Income (loss) before income taxes	45,499	(12,953)	(14,662)	(34,651)
Income tax expense (benefit)	2,145	(72)	(1,206)	(448)
Net income (loss)	$ 43,354	$ (12,881)	$ (13,456)	$ (34,203)
Net income (loss) per share:				
Basic	$ 0.54	$ (0.16)	$ (0.17)	$ (0.43)
Diluted	$ 0.52	$ (0.16)	$ (0.17)	$ (0.43)

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, 2021				
	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Deficit	Total Stockholders' Equity
	(in thousands)				
December 31, 2020	$ 85	$ 915,877	$ (49,995)	$ (151,931)	$ 714,036
Shares withheld for payment of taxes on equity awards and other	—	(1,442)	—	—	(1,442)
Stock based compensation	—	3,995	—	—	3,995
Issuance of common stock	1	—	—	—	1
Dividends declared on common stock, $0.04/share	—	(3,474)	—	—	(3,474)
Net loss	—	—	—	(21,322)	(21,322)
March 31, 2021	86	914,956	(49,995)	(173,253)	691,794
Shares withheld for payment of taxes on equity awards and other	—	(78)	—	—	(78)
Stock based compensation	—	3,042	—	—	3,042
Dividends declared on common stock, $0.04/share	—	(3,219)	—	—	(3,219)
Net loss	—	—	—	(12,881)	(12,881)
June 30, 2021	$ 86	$ 914,701	$ (49,995)	$ (186,134)	$ 678,658

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

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,	
	2022	2021
	(in thousands)	
Cash flows from operating activities:		
Net loss	$ (13,456)	$ (34,203)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	77,832	69,690
Amortization of debt issuance costs	971	2,728
Stock-based compensation expense	8,222	6,639
Deferred income taxes	(509)	(473)
Decrease in allowance for doubtful accounts	—	(500)
Other operating (income) expenses	(187)	142
Derivative activities:		
Total losses	184,123	69,788
Cash settlements on derivatives	(69,780)	(36,581)
Changes in assets and liabilities:		
Increase in accounts receivable	(30,990)	(11,189)
Decrease (increase) decrease in other assets	3,526	(7,490)
Increase in accounts payable and accrued expenses	1,728	3,406
Decrease in other liabilities	(1,708)	(2,098)
Net cash provided by operating activities	159,772	59,859
Cash flows from investing activities:		
Capital expenditures:		
Capital expenditures	(61,706)	(67,030)
Changes in capital expenditures accruals	5,363	6,934
Acquisitions, net of cash received	(19,080)	(825)
Proceeds from sale of property and equipment and other	—	409
Net cash used in investing activities	(75,423)	(60,512)
Cash flows from financing activities:		
Borrowings under 2021 RBL credit facility	192,000	—
Repayments on 2021 RBL credit facility	(192,000)	—
Dividends paid on common stock	(20,275)	(3,466)
Shares withheld for payment of taxes on equity awards and other	(4,102)	(1,520)
Purchase of treasury stock	(22,760)	—
Net cash used in financing activities	(47,137)	(4,986)
Net increase (decrease) in cash and cash equivalents	37,212	(5,639)
Cash and cash equivalents:		
Beginning	15,283	80,557
Ending	$ 52,495	$ 74,918

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

Note 1—Basis of Presentation

"Berry Corp." refers to Berry Corporation (bry), a Delaware corporation, which is the sole member of each of its three Delaware limited liability company subsidiaries: (1) Berry Petroleum Company, LLC ("Berry LLC"), (2) CJ Berry Well Services Management, LLC ("C&J Management") and (3) C&J Well Services, LLC ("CJWS"). As the context may require, the "Company", "we", "our" or similar words refer to Berry Corp. and its subsidiary, Berry LLC, and as of October 1, 2021 this also includes CJWS and CJ Management.

Nature of Business

We are a western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived conventional oil and gas reserves in the San Joaquin basin of California and the Uinta basin of Utah, with well servicing and abandonment capabilities in California. Since October 1, 2021, we have operated in two business segments: (i) development and production ("D&P") and (ii) well servicing and abandonment.

Berry Corp. was incorporated under Delaware law in February 2017 and its common stock began trading on NASDAQ under the symbol "bry" in July 2018. Berry Corp. operates through its three wholly owned subsidiaries. Berry LLC owns and operates our oil and gas assets (D&P segment). In January 2022, we divested our natural gas properties in the Piceance basin of Colorado. On October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California, which now constitutes our well servicing and abandonment segment, also referred to as "CJWS".

Principles of Consolidation and Reporting

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

We prepared this report pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC") applicable to interim financial information, which permit the omission of certain disclosures to the extent they have not changed materially since the latest annual financial statements. We believe our disclosures are adequate to make the disclosed information not misleading. The results reported in these unaudited condensed consolidated financial statements may not accurately forecast results for future periods. This Quarterly Report on Form 10-Q should be read in conjunction with the consolidated financial statements and the notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2021.

New Accounting Standards Adopted

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which requires lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842)*, which is an update to the lease standard providing an optional transition approach for land easements allowing entities to evaluate only new or modified land easements. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842)*, which provided optional transition relief allowing a prospective approach in applying the new rules by not adjusting comparative period financial information for the effects of the new rules and not requiring disclosures for periods before the effective date. As an emerging growth company, we have elected to delay the adoption of these rules until they are applicable to non-SEC issuers. During the second quarter of 2020, this adoption date was further delayed by

FASB until fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. We adopted these rules in the first quarter of 2022 prospectively.

Note 2—Debt

The following table summarizes our outstanding debt:

	June 30, 2022	December 31, 2021	Interest Rate	Maturity	Security
	(in thousands)				
2021 RBL Facility	$ —	$ —	variable rates 6.8% (2022) and 5.3% (2021)	August 26, 2025	Mortgage on 90% of Present Value of proven oil and gas reserves and lien on certain other assets
2026 Notes	400,000	400,000	7.0%	February 15, 2026	Unsecured
Long-Term Debt - Principal Amount	400,000	400,000			
Less: Debt Issuance Costs	(4,865)	(5,434)			
Long-Term Debt, net	$ 395,135	$ 394,566			

Deferred Financing Costs

We incurred legal and bank fees related to the issuance of debt. At June 30, 2022 and December 31, 2021, debt issuance costs for the 2021 RBL Facility (as defined below) reported in "other noncurrent assets" on the balance sheet were approximately $4 million and $5 million net of amortization, respectively. At June 30, 2022 and December 31, 2021, debt issuance costs, net of amortization, for the unsecured notes due February 2026 (the "2026 Notes") reported in "Long-Term Debt, net" on the balance sheet was approximately $5 million.

For each of the three month periods ended June 30, 2022 and 2021, the amortization expense for the 2021 RBL Facility, the 2017 RBL Facility (as defined below) and the 2026 Notes, combined, was approximately $1 million. For each of the six month periods ended June 30, 2022 and 2021, the amortization expense for the 2021 RBL Facility, the 2017 RBL Facility and the 2026 Notes, combined, was approximately $1 million and $3 million, respectively. The amortization of debt issuance costs is presented in "interest expense" in the condensed consolidated statements of operations.

Fair Value

Our debt is recorded at the carrying amount on the balance sheets. The carrying amount of the 2021 RBL Facility approximates fair value, classified as Level 1, because the interest rates are variable and reflect market rates. The fair value of the 2026 Notes was approximately $389 million and $400 million at June 30, 2022 and December 31, 2021, respectively.

2021 RBL Facility

On August 26, 2021, Berry Corp, as a guarantor, together with Berry LLC, as the borrower, entered into a credit agreement that provided for a revolving loan with up to $500 million of commitment, subject to a reserve borrowing base (as amended by the First Amendment, the Second Amendment and the Third Amendment, each as defined below, the "2021 RBL Facility"). Our initial borrowing base was $200 million. The 2021 RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $20 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the 2021 RBL Facility on a dollar for dollar basis. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. Borrowing base redeterminations generally become effective each May and November, although the borrower and the lenders may each make one interim redetermination between scheduled redeterminations. In December 2021, we completed the first scheduled semi-annual borrowing base redetermination and entered into that certain First Amendment to Credit Agreement (the "First Amendment"), which resulted in a reaffirmed borrowing base at $200 million and changes to the hedging covenants in respect of the exclusion of short puts or similar derivatives in the calculation of minimum and maximum hedging requirements.

In May 2022, Berry Corp., as a guarantor, and Berry LLC, as the borrower, entered into that certain Second Amendment to Credit Agreement and Limited Consent and Waiver (the "Second Amendment") pursuant to which, among other things, the requisite lenders under the 2021 RBL Facility (i) consented to certain dividends and distributions and to certain investments made by Berry LLC in C&J Well Services, LLC and/or CJ Berry Well Services Management, LLC, in each case, as further described therein, (ii) waived certain minimum hedging requirements for the time periods described therein, (iii) waived any breach, default or event of default which may have arisen as a result of any of the foregoing, (iv) amended the restricted payments covenant to give us additional flexibility to make restricted payments, subject to satisfaction of certain leverage and availability conditions and other conditions described below and in the Second Amendment and (v) amended the minimum hedging covenant to not, until October 1, 2022, require hedges for any full calendar month from and after January 1, 2025, as further described in the Second Amendment. In May 2022, we also completed our semi-annual borrowing base redetermination and entered into the Third Amendment to the Credit Agreement (the "Third Amendment"), which among other things (1) increased the borrowing base from $200 million to $250 million; (2) established the Aggregate Elected Commitment Amounts (as defined in the 2021 RBL Facility) at $200 million initially; and (3) converted all outstanding Eurodollar Loans (into Term Benchmark Loans (each as defined in the 2021 RBL Facility) with an initial interest period of one-month's duration and otherwise give effect to the transition from the London interbank offered rate ("LIBOR") to the secured overnight financing rate ("SOFR") by replacing the adjusted LIBOR rate with the term SOFR rate for one, three or six months plus 0.1% (subject to a floor of 0.5%).

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

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

The 2021 RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a leverage ratio of not more than 3.0 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of June 30, 2022, our leverage ratio and current ratio were 1.3:1.0 and 2.5:1.0, respectively. In addition, the 2021 RBL Facility currently provides that, to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the 2021 RBL Facility as of June 30, 2022.

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

From and after August 26, 2022, the 2021 RBL Facility permits us to repurchase certain indebtedness so long as both before and after giving pro forma effect to such repurchase, no default or event of default exists, availability is equal to or greater than 20% of the borrowing base and our pro forma leverage ratio is less than or equal to 2.0 to 1.0. The 2021 RBL Facility also permits us to make restricted payments so long as both before and after giving pro forma effect to such distribution, no default or event of default exists, availability exceeds 75% of the borrowing base, and our pro forma leverage ratio is less than or equal to 1.5 to 1.0. In addition, we can make other restricted payments in an aggregate amount not to exceed 100% of Free Cash Flow (as defined under the 2021 RBL Facility) for the fiscal quarter most recently ended prior to such distribution so long as, in addition to other conditions and limitations as described in the 2021 RBL Facility, both before and after giving pro forma effect to such distribution, no default or event of default exists, availability is greater than 20% of the borrowing base and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

Berry LLC is the borrower on the 2021 RBL Facility and Berry Corp. is the guarantor. Each future subsidiary of Berry Corp., with certain exceptions, is required to guarantee our obligations and obligations of the other guarantors under the 2021 RBL Facility and under certain hedging transactions and banking services arrangements (the “Guaranteed Obligations”). The lenders under the 2021 RBL Facility hold a mortgage on at least 90% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions.

As of June 30, 2022, we had no borrowings outstanding, $7 million in letters of credit outstanding and approximately $193 million of available borrowing capacity under the 2021 RBL Facility.

2017 RBL Facility

On July 31, 2017, we entered into a credit agreement that provided for a revolving loan with up to $1.5 billion of commitment, subject to a reserve borrowing base (“2017 RBL Facility”). On August 26, 2021, we cancelled the 2017 RBL Facility agreement, which had a borrowing base of $200 million and there were no borrowings outstanding at the time of cancellation.

Debt Repurchase Program

In February 2020, our Board of Directors adopted a program to spend up to $75 million for the opportunistic repurchase of our 2026 Notes. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and do not obligate Berry Corp. to purchase the 2026 Notes during any period or at all. We have not yet repurchased any 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 the hedging requirements of the 2021 RBL Facility, we target covering our operating expenses and a majority of our fixed charges, which includes capital needed to sustain production levels, as well as interest and fixed dividends as applicable, with the oil and gas sales hedges for a period of up to three years out. Additionally, we target fixing the price for a large portion of our natural gas purchases used in our steam operations for up to three years. We have also entered into Utah gas transportation contracts to help reduce the price fluctuation exposure, however these do not qualify as hedges. We also, from time to time, have entered into agreements to purchase a portion of the natural gas we require for our operations, which we do not record at fair value as derivatives because they qualify for normal purchases and normal sales exclusions. We had no such transactions in the periods presented.

For fixed-price oil and gas sales swaps, we are the seller, so we make settlement payments for prices above the indicated weighted-average price per barrel and per mmbtu, respectively, and receive settlement payments for prices below the indicated weighted-average price per barrel and per mmbtu, respectively.

For our long put spreads, in addition to any deferred premium payments, we would receive settlement payments for prices below the indicated highest price of the long put with the maximum payment received per barrel equal to the difference between the indicated prices of the long and short put. No payment would be made or received for prices above the highest indicated price of the long put. The short put spreads offset the long put spreads.

For our purchased oil puts, we would receive settlement payments for prices below the indicated weighted-average price per barrel of Brent. For some of our 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, 2022 we have net payable deferred premiums of approximately $7 million, which is reflected in the mark-to-market valuation and will be payable beginning in 2022 through 2024.

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

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

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

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.

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

As of June 30, 2022, we had the following hedges for our crude oil production and natural gas purchases.

	Q3 2022	Q4 2022	FY 2023	FY 2024	FY 2025
Brent - Crude Oil production					
Swaps					
Hedged volume (bbls)	1,380,000	1,288,000	3,433,528	1,917,000	—
Weighted-average price ($/bbl)	$ 77.73	$ 76.07	$ 73.06	$ 75.52	$ —
Put Spreads					
Long $50/$40 Put Spread hedged volume (bbls)	414,000	414,000	2,555,000	1,647,000	—
Short $50/$40 Put Spread hedged volume (bbls)	46,000	46,000	365,000	366,000	—
Producer Collars					—
Hedged volume (bbls)	—	—	1,460,000	1,098,000	—
Weighted-average price ($/bbl)	$ —	$ —	$40.00/$106.00	$40.00/$105.00	$ —
Henry Hub - Natural Gas purchases					
Consumer Collars					
Hedged volume (mmbtu)	3,680,000	3,680,000	5,430,000	—	—
Weighted-average price ($/mmbtu)	$4.00/$2.75	$4.00/$2.75	$4.00/$2.75	$ —	$ —
NWPL - Natural Gas purchases					
Swaps					
Hedged volume (mmbtu)	—	1,220,000	12,800,000	7,320,000	6,080,000
Weighted-average price ($/mmbtu)	$ —	$ 6.40	$ 5.48	$ 4.27	$ 4.27

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, 2022 and December 31, 2021:

	June 30, 2022			
	Balance Sheet Classification	Gross Amounts Recognized at Fair Value	Gross Amounts Offset in the Balance Sheet	Net Fair Value Presented in the Balance Sheet
		(in thousands)		
Assets:				
Commodity Contracts	Current assets	$ 22,794	$ (22,794)	$ —
Commodity Contracts	Non-current assets	27,674	(27,674)	—
Liabilities:				
Commodity Contracts	Current liabilities	(123,857)	22,794	(101,063)
Commodity Contracts	Non-current liabilities	(87,278)	27,674	(59,604)
Total derivatives		$ (160,667)	$ —	$ (160,667)

	December 31, 2021						
	Balance Sheet Classification		Gross Amounts Recognized at Fair Value		Gross Amounts Offset in the Balance Sheet		Net Fair Value Presented in the Balance Sheet
	(in thousands)						
Assets:							
Commodity Contracts	Current assets	$	5,360	$	(5,360)	$	—
Commodity Contracts	Non-current assets		29,828		(28,758)		1,070
Liabilities:							
Commodity Contracts	Current liabilities		(34,985)		5,360		(29,625)
Commodity Contracts	Non-current liabilities		(47,335)		28,758		(18,577)
Total derivatives		$	(47,132)	$	—	$	(47,132)

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

We minimize the credit risk in derivative instruments by limiting our exposure to any single counterparty. In addition, our 2021 RBL Facility prevents us from entering into hedging arrangements that are secured, except with our lenders and their affiliates that have margin call requirements, that otherwise require us to provide collateral or with a non-lender counterparty that does not have an A or A2 credit rating or better from Standards & Poor's or Moody's, respectively. In accordance with our standard practice, our commodity derivatives are subject to counterparty netting under agreements governing such derivatives which partially mitigates the counterparty nonperformance risk.

Note 4—Lawsuits, Claims, Commitments and Contingencies

In the normal course of business, we, or our subsidiaries, are the subject of, or party to, pending or threatened legal proceedings, contingencies and commitments involving a variety of matters that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, fines and penalties, remediation costs, or injunctive or declaratory relief.

We accrue for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at June 30, 2022 and December 31, 2021. 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, 2022, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matter

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Torres Lawsuit") in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (collectively, the "Defendants"). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act, on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company's 2018 IPO; or (ii) Berry Corp.'s securities between July 26, 2018 and November 3, 2020 (the "Class Period"). In particular, the complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company's business, operational efficiency and stability, and compliance policies, that artificially inflated the Company's stock price, resulting in injury to the purported class members when the value of Berry Corp.'s common stock declined following release of its financial results for the third quarter of 2020 on November 3, 2020.

On January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Exchange Act, alleging, among other things, that the Company and the individual Defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company's permits and permitting processes. The amended complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys' fees and costs. The Defendants filed a Motion to Dismiss on January 24, 2022, for which the Court's ruling is pending.

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

Note 5—Equity

Cash Dividends

Our Board of Directors approved regular fixed cash dividends of $0.06 per share on our common stock for each of the first two quarters of 2022, which were paid in April and July 2022. The Board of Directors approved a $0.13 per share variable dividend based on our first quarter results, which was paid in June 2022. In July 2022, the Board of Directors approved a $0.06 per share regular fixed cash dividend, as well as a variable dividend of $0.56 based on the second quarter results, each of which is expected to be paid in August 2022.

Stock Repurchase Program

The Company repurchased 2,000,000 shares during the three months ended June 30, 2022 for approximately $23 million. As of June 30, 2022, the Company had repurchased a total of 7,528,704 shares under the stock repurchase program for approximately $75 million in aggregate. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company intends to allocate a portion of Discretionary Free Cash Flow to opportunistic share repurchases.

In April 2022, our Board of Directors approved an increase of $102 million to the Company's stock repurchase authorization bringing the Company's total share repurchase authority to $150 million. As of June 30, 2022, the Company's remaining total share repurchase authority is $127 million, after the repurchases made in the second quarter of 2022. The Board's authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions, subject to market conditions and other factors, up to the aggregate amount authorized by the Board. The Board's authorization has no expiration date.

Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and 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 February 2022, the Company granted awards of approximately 1,300,000 shares of restricted stock units (“RSUs”), which will vest annually in equal amounts over three years. In March 2022, the Company granted awards of approximately 611,000 shares performance-based restricted stock units (“PSUs”), which will cliff vest, if at all, at the end of a three year performance period. The RSUs awarded are equity awards as they will be settled in stock. The PSUs awarded were accounted for as liability awards as of March 31, 2022, but converted to equity awards during the second quarter of 2022. The accounting of the awards was converted as a result of the 2022 Omnibus Incentive Plan (the “2022 Plan”) being approved by the stockholders in May 2022. The fair value of these awards was approximately $19 million on the date the 2022 Plan was approved and this will be the value of these awards through the date of their vesting.

The RSUs awarded in February 2022 are solely time-based awards. Of the PSUs awarded to certain Berry employees (excluding CJWS employee awards) in March 2022, (a) 50% of such will vest, if at all, based on a total stockholder return (“TSR”) performance metric (the “TSR PSUs”), which is defined as the capital gains per share of stock plus dividends paid assuming reinvestment, with TSR measured on an absolute basis and relative to the TSR of the 44 exploration and production companies in the Vanguard World Fund - Vanguard Energy ETF Index plus the S&P SmallCap 600 Value Index (collectively, the “Peer Group”) during the performance period and (b) 50% of such awards will vest, if at all, based on the consolidated Company's average cash returned on invested capital (“CROIC PSUs”) over the performance period. The PSUs awarded to certain CJWS employees in March 2022 will vest, if at all based on the CJWS average cash returned on invested capital (“ROIC PSUs”) over the performance period. Depending on the results achieved during the three-year performance period, the actual number of shares that a grant recipient receives at the end of the period may range from 0% to 250% of the TSR PSUs granted and from 0% to 200% of the CROIC and ROIC PSUs granted.

The fair value of the RSUs was determined using the grant date stock price. The fair value of the CROIC PSUs and ROIC PSUs was determined using the stock price and estimated performance as of the reporting period as the awards are liability awards. The fair value of the TSR PSUs was determined using a Monte Carlo simulation analysis to estimate the total shareholder return ranking of the Company, including a comparison against the Peer Group over the performance periods as of the reporting period as the awards are liability awards. The expected volatility of the Company’s common stock at the date of grant was estimated based on average volatility rates for the Company and selected guideline public companies. The dividend yield assumption was based on the then current annualized declared dividend. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate three-year performance measurement period.

Note 6—Supplemental Disclosures to the Financial Statements

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

	June 30, 2022	December 31, 2021
	(in thousands)	
Prepaid expenses	$ 19,822	$ 26,840
Materials and supplies	8,600	9,533
Deposits	3,773	6,415
Oil inventories	2,702	2,933
Other	225	225
Total other current assets	$ 35,122	$ 45,946

Other non-current assets at June 30, 2022 included approximately $7 million of operating lease right-of-use assets, net of amortization and $4 million of deferred financing costs, net of amortization. At December 31, 2021 other non-current assets included approximately $5 million of deferred financing costs, net of amortization.

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

	June 30, 2022	December 31, 2021
	(in thousands)	
Accounts payable-trade	$ 19,420	$ 17,699
Accrued expenses	68,819	62,962
Royalties payable	26,799	24,816
Greenhouse gas liability - current portion	—	7,513
Taxes other than income tax liability	8,469	8,273
Accrued interest	10,682	10,736
Dividends payable	4,726	4,800
Asset retirement obligations - current portion	20,000	20,000
Operating lease liability	1,762	—
Other	6	725
Total accounts payable and accrued expenses	$ 160,683	$ 157,524

The decrease of $4 million in the long-term portion of the asset retirement obligations from $144 million at December 31, 2021 to $140 million at June 30, 2022 was due to $11 million of liabilities settled during the period, and a $1 million reduction related to property sales. These decreases were offset by $5 million of accretion and $3 million of liabilities incurred.

Other noncurrent liabilities at June 30, 2022 included approximately $26 million of greenhouse gas liability and $6 million of operating lease noncurrent liability. For December 31, 2021, we had $18 million in greenhouse gas liability.

Supplemental Information on the Statement of Operations

For the three months ended June 30, 2022, other operating expenses were less than $1 million. For the three months ended June 30, 2021, other operating expenses mainly consisted of $2 million of supplemental property tax assessments and royalty audit charges, mostly offset by $2 million of employee retention credits.

For the six months ended June 30, 2022, other operating expenses were $4 million and mainly consisted of over $2 million in royalty audit charges incurred prior to our emergence and restructuring in 2017, and approximately $1 million loss on the divestiture of the Piceance properties. For the six months ended June 30, 2021, other operating expenses were approximately $1 million and mainly consisted of approximately $3 million of supplemental property tax assessments and royalty audit charges and tank rental costs, partially offset by $2 million of employee retention credits.

Supplemental Cash Flow Information

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

	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021
	(in thousands)	
Supplemental Disclosures of Significant Non-Cash Investing Activities:		
Material inventory transfers to oil and natural gas properties	$ 1,011	$ 1,437
Supplemental Disclosures of Cash Payments (Receipts):		
Interest, net of amounts capitalized	$ 14,988	$ 14,925
Income taxes payments	$ 2,484	$ —

Cash and cash equivalents consist primarily of highly liquid investments with original maturities of three months or less and are stated at cost, which approximates fair value. As part of our cash management system, we use a controlled disbursement account to fund cash distribution checks presented for payment by the holder. Checks issued but not yet presented to banks may result in overdraft balances for accounting purposes and have been included in “accounts payable and accrued expenses” in the condensed consolidated balance sheets. Such amounts are immaterial as of June 30, 2022 and December 31, 2021.

Note 7—Earnings Per Share

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

The RSUs and PSUs are not a participating security as the dividends are forfeitable. For the three months ended June 30, 2022, 3,419,000 incremental RSU and PSU shares were included in the diluted EPS calculation. For the three months ended June 30, 2021 and the six months ended June 30, 2022 and 2021, no incremental RSU or PSU shares were included in the diluted EPS calculation as their effect was anti-dilutive under the “if converted” method.

	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021
	(in thousands except per share amounts)			
Basic EPS calculation				
Net income (loss)	$ 43,354	$ (12,881)	$ (13,456)	$ (34,203)
Weighted-average shares of common stock outstanding	79,596	80,471	79,945	80,294
Basic income (loss) per share	$ 0.54	$ (0.16)	$ (0.17)	$ (0.43)
Diluted EPS calculation				
Net income (loss)	$ 43,354	$ (12,881)	$ (13,456)	$ (34,203)
Weighted-average shares of common stock outstanding	79,596	80,471	79,945	80,294
Dilutive effect of potentially dilutive securities[1]	3,419	—	—	—
Weighted-average common shares outstanding - diluted	83,015	80,471	79,945	80,294
Diluted income (loss) per share	$ 0.52	$ (0.16)	$ (0.17)	$ (0.43)

(1) We excluded 2.9 million of combined RSUs and PSUs from the dilutive weighted-average common shares outstanding for the three months ended June 30, 2021, because their effect was anti-dilutive. We excluded approximately 3.5 million and 2.6 million of combined RSUs and PSUs from the dilutive weighted-average common shares outstanding for the six months ended June 30, 2022 and June 30, 2021, because their effect was anti-dilutive.

Note 8—Revenue Recognition

We derive revenue from sales of oil, natural gas and natural gas liquids ("NGL"), with additional revenue generated from sales of electricity and marketing activities. Effective October 1, 2021, we completed the acquisition of CJWS, a well servicing and abandonment business. 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, 2022 and 2021:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
	(in thousands)			
Oil sales	$ 230,617	$ 141,309	$ 433,341	$ 263,668
Natural gas sales	7,349	5,415	13,331	17,492
Natural gas liquids sales	2,105	1,051	3,750	1,880
Service revenue	46,178	—	86,014	—
Electricity sales	7,419	6,888	12,838	16,957
Marketing revenues	—	121	289	2,355
Other revenues	120	118	165	255
Revenues from contracts with customers	293,788	154,902	549,728	302,607
Losses on oil and gas sales derivatives	(40,658)	(55,653)	(202,516)	(109,157)
Total revenues and other	$ 253,130	$ 99,249	$ 347,212	$ 193,450

Note 9—Acquisition and Divestiture

2022

Piceance Divestiture

In January 2022, we completed the divestiture of all of our natural gas properties in Colorado, which were in the Piceance basin. The divestiture closed with a loss of approximately $1 million.

Antelope Creek Acquisition

In February 2022, we completed the acquisition of oil and gas producing assets in the Antelope Creek area of Utah for approximately $18 million. These assets are adjacent to our existing Uinta assets and prior to our acquisition produced approximately 600 boe/d.

Note 10—Segment Information

As of October 1, 2021, we have operated in two business segments: (i) development and production and (ii) well servicing and abandonment. The development and production segment is engaged in the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, as well as Utah. On October 1, 2021, we completed the acquisition of an upstream well servicing and abandonment business in California, which became a reportable segment (well servicing and abandonment) under U.S. GAAP. Prior to October 1, 2021, we did not have more than one reportable segment, thus no prior period segment information has been presented.

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

	Three Months Ended June 30, 2022			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues - excluding hedges	$ 247,610	$ 46,178	$ —	$ 293,788
Net income (loss)	$ 68,885	$ 3,307	$ (28,838)	$ 43,354
Adjusted EBITDA	$ 116,942	$ 6,200	$ (13,395)	$ 109,747
Capital expenditures	$ 32,134	$ 1,066	$ 886	$ 34,086
Total assets	$ 1,456,164	$ 71,543	$ 2,678	$ 1,530,385

	Six Months Ended June 30, 2022			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Revenues - excluding hedges	$ 463,714	$ 86,014	$ —	$ 549,728
Net income (loss)	$ 34,594	$ 3,023	$ (51,073)	$ (13,456)
Adjusted EBITDA	$ 222,591	$ 9,500	$ (26,632)	$ 205,459
Capital expenditures	$ 58,571	$ 1,694	$ 1,441	$ 61,706
Total assets	$ 1,456,164	$ 71,543	$ 2,678	$ 1,530,385

Adjusted EBITDA is the measure reported to the chief operating decision maker (CODM) for purposes of making decisions about allocating resources to and assessing performance of each segment. 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. Adjusted EBITDA is calculated as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and unusual and infrequent items. While Adjusted EBITDA is a non-GAAP measure, the amounts included in the calculations of Adjusted EBITDA, were computed in accordance with GAAP. This measure is 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. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

	Three Months Ended June 30, 2022			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 68,885	$ 3,307	$ (28,838)	$ 43,354
Add (Subtract):				
Interest expense	—	—	7,729	7,729
Income tax expense	—	—	2,145	2,145
Depreciation, depletion, and amortization	33,956	3,017	1,082	38,055
Losses on derivatives	51,319	—	—	51,319
Net cash paid for scheduled derivative settlements	(37,628)	—	—	(37,628)
Other operating expenses (income)	30	(210)	533	353
Stock compensation expense	380	86	3,954	4,420
Adjusted EBITDA	$ 116,942	$ 6,200	$ (13,395)	$ 109,747

	Six Months Ended June 30, 2022			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
	(in thousands)			
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 34,594	$ 3,023	$ (51,073)	$ (13,456)
Add (Subtract):				
Interest expense	—	—	15,404	15,404
Income tax benefit	—	—	(1,206)	(1,206)
Depreciation, depletion, and amortization	69,430	6,196	2,206	77,832
Losses on derivatives	184,123	—	—	184,123
Net cash paid for scheduled derivative settlements	(69,780)	—	—	(69,780)
Other operating expenses (income)	3,525	(36)	633	4,122
Stock compensation expense	699	119	7,404	8,222
Non-recurring costs	—	198	—	198
Adjusted EBITDA	$ 222,591	$ 9,500	$ (26,632)	$ 205,459

Note 11—Leases

In the first quarter of 2021, we adopted ASC 842 using the modified retrospective approach that requires us to determine our lease balances as of the date of adoption. Prior periods continue to be reported under accounting standards in effect for those periods.

The Company determines if an arrangement is a lease at inception of the contract. If an arrangement is a lease, the present value of the related lease payments is recorded as a liability and an equal amount is capitalized as a right of use asset on the Company's balance sheet. Right of use assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. We have long-term operating leases generally for offices. The Company's estimated incremental borrowing rate, determined at the lease commencement date using the Company's average secured borrowing rate, is used to calculate present value. The weighted average estimated incremental borrowing rate used for the three months ended June 30, 2022 was 5%.

Leases with an initial term of 12 months or less are not recorded on the balance sheet and the Company recognizes lease expense for these leases on a straight-line basis over the lease term.

The components of lease expense are as follows:

	Three Months Ended June 30, 2022	Six Months Ended June 30, 2022
	(in thousands)	
Lease Cost		
Operating lease cost	$ 503	$ 986
Total net lease cost	$ 503	$ 986

The following table presents supplemental interim consolidated balance sheet information related to leases as of June 30, 2022.

	Six Months Ended June 30, 2022	Balance Sheet Classification
	(in thousands)	
Leases		
Assets		
Operating lease assets	$ 7,150	Other noncurrent assets
Total assets	$ 7,150	
Liabilities		
Operating lease liability	$ 1,762	Accounts payable and accrued expenses
Operating lease noncurrent liability	6,017	Other noncurrent liabilities
Total liabilities	$ 7,779	

	Six Months Ended June 30, 2022
Long-Term and Discount Rate	
Weighted-average remaining lease term:	
Operating Lease	4.7 years
Weighted-average discount rate:	
Operating Lease	5 %

The following table presents a schedule of future minimum lease payments required under all operating lease agreements as of June 30, 2022.

	As of June 30, 2022 Operating Leases (in thousands)
2022	$ 1,082
2023	1,963
2024	1,650
2025	1,542
2026	1,549
Thereafter	934
Total lease payments	8,720
Less imputed interest	(941)
Total lease obligations	7,779
Less current obligations	(1,762)
Long-term lease obligations	$ 6,017

Supplemental unaudited interim consolidated cash flow information related to leases is as follows:

	Six Months Ended June 30, 2022 (in thousands)
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 1,052
ROU assets obtained in exchange for operating lease liabilities	$ 7,956

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

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with our interim unaudited consolidated financial statements and related notes presented in this Quarterly Report on Form 10-Q, as well as our audited consolidated financial statements and related notes thereto contained in our Annual Report on Form 10-K for the year ended December 31, 2021 (the "Annual Report") filed with the Securities and Exchange Commission ("SEC"). When we use the terms "we," "us," "our," "Berry," the "Company" or similar words in this report, we are referring to, as the context may require, (i) for periods prior to October 1, 2021, Berry Corporation (bry), a Delaware corporation (formerly known as Berry Petroleum Corporation,"Berry Corp."), together with its subsidiary Berry Petroleum, LLC, a Delaware limited liability company ("Berry LLC"); and (ii) for periods on or after October 1, 2021, Berry Corp. together with its subsidiaries, Berry LLC, CJ Berry Well Services Management, LLC, a Delaware limited liability company ("C&J Management"), and C&J Well Services, LLC, a Delaware limited liability company ("C&J Well Services").

Our Company

We are a western United States independent upstream energy company with a focus on onshore, low geologic risk, long-lived conventional oil and gas reserves in the San Joaquin basin of California and the Uinta basin of Utah, with newly acquired well servicing and abandonment capabilities in California. Since October 1, 2021, we have operated in two business segments: (i) development and production ("D&P") and (ii) well servicing and abandonment.

The assets in our D&P business, in the aggregate, are characterized by high oil content (our California assets are 100% oil) and are predominantly located in rural areas with low population. In California, we focus on conventional, shallow oil reservoirs, the drilling and completion of which are relatively low-cost in contrast to unconventional resource plays. The California oil market has primarily Brent-influenced pricing which has typically realized premium pricing to WTI. All of our California assets are located in the 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 substantial data produced over the basin's long history, its reservoir characteristics are well understood, which enables predictable, repeatable, low geological risk and low-cost development opportunities. We also have upstream assets in the low-operating cost, oil-rich reservoirs in the Uinta basin of Utah. In January 2022, we divested our natural gas properties in the Piceance basin of Colorado.

On October 1, 2021, we completed the acquisition of one of the largest upstream well servicing and abandonment businesses in California, which operates as CJWS and now constitutes our well servicing and abandonment segment. CJWS provides wellsite services in California to oil and natural gas production companies, with a focus on well servicing, well abandonment services and water logistics. CJWS' services include rig-based and coiled tubing-based well maintenance and workover services, recompletion services, fluid management services, fishing and rental services, and other ancillary oilfield services. Additionally, CJWS performs plugging and abandonment services on wells at the end of their productive life, which we believe creates a strategic growth opportunity for Berry. CJWS is a synergistic fit with the services required by our oil and gas operations and supports our commitment to be a responsible operator and reduce our emissions, including through the proactive plugging and abandonment of wells. Additionally, CJWS is critical to advancing our strategy to work with the State of California to reduce fugitive emissions - including methane and carbon dioxide - from idle wells. There are approximately 35,000 idle wells estimated to be in California according to third-party sources. We believe that CJWS is uniquely positioned to capture both state and federal funds to help remediate orphan idle wells (an idle well that has been abandoned by the operator and as a result becomes a burden of the State is referred to as an orphan well), in addition to helping third-party customers address their idle wells.

Since our Initial Public Offering (IPO) in July 2018, we have demonstrated our commitment to returning a substantial amount of capital to shareholders and in 2022, we reinforced this commitment by initiating a shareholder return model designed to significantly increase cash returns to our shareholders from our Discretionary Free Cash Flow (as defined and discussed below). In accordance with the shareholder return model, in May 2022, we declared our first variable dividend payment of $0.13 per share based on Discretionary Free Cash Flow generated in the first quarter of 2022, and in July 2022, we declared a variable dividend payment of $0.56 per share based on Discretionary Free Cash Flow generated in the second quarter of 2022. Including the aggregate $0.62 dividends declared in July (to be paid in August), as of July 31, 2022 we will have returned to our shareholders (a) $92 million consisting of $69 million of fixed and variable dividends and $23 million of share repurchases in 2022, and (b) $226 million consisting of $151 million of fixed and variable dividends and $75 million of share repurchases since our IPO, which represents 205% of our IPO proceeds

We define “Discretionary Free Cash Flow,” which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. This supplemental non-GAAP financial measure is used by management, including as described below under “Management’s Discussion and Analysis—How We Plan and Evaluate Operations,” as well as by external users of our financial statements. Please see “Management’s Discussion and Analysis—Non-GAAP Financial Measures” for a reconciliation of Discretionary Free Cash Flow to cash provided by operating activities, our most directly comparable financial measure calculated and presented in accordance with GAAP. Like our business model, this shareholder return model is simple and further demonstrates our commitment to return capital to our shareholders.

We believe that the successful execution of our strategy across our low-declining, oil-weighted production base coupled with extensive inventory of identified drilling locations with attractive full-cycle economics will support our objectives to generate Discretionary Free Cash Flow to fund our operations and optimize capital efficiency, while maintaining a low leverage profile and focusing on attractive organic and strategic growth through commodity price cycles. “Adjusted EBITDA” is also a non-GAAP financial measure defined as earnings before interest expense, income taxes, depreciation, depletion, and amortization, derivative gains or losses net of cash received or paid for scheduled derivative settlements, impairments, stock compensation expense, and other unusual and infrequent items. These supplemental non-GAAP financial measures are used by management, including as described below under “Management’s Discussion and Analysis—How We Plan and Evaluate Operations,” as well as by external users of our financial statements. Please see “Management’s Discussion and Analysis—Non-GAAP Financial Measures” for reconciliations of Adjusted EBITDA to net cash provided by operating activities and of Adjusted EBITDA to net income (loss), our most directly comparable financial measures calculated and presented in accordance with GAAP.

We have a progressive approach to growing and evolving our businesses in today's dynamic oil and gas industry. Our strategy includes proactively engaging the many forces driving our industry and impacting our operations, whether positive or negative, to maximize the utility of our assets, create value for shareholders, and support environmental goals that align with safe, more efficient and lower emission operations. As part of our commitment to creating long-term value for our stockholders, we are dedicated to conducting our operations in an ethical, safe and responsible manner, to protecting the environment, and to taking care of our people and the communities in which we live and operate. We believe that oil and gas will remain an important part of the energy landscape going forward and our goal is to conduct our business safely and responsibly, while supporting economic stability and social equity through engagement with our stakeholders. We recognize the oil and gas industry’s role in the energy transition and are determined to be part of the solution.

How We Plan and Evaluate Operations

We use the following metrics to manage and assess the performance of our operations: (a) Adjusted EBITDA; (b) Discretionary Free Cash Flow for shareholder returns; (c) operating expenses; (d) environmental, health & safety (“EH&S”) results; (e) general and administrative expenses; (f) production from our D&P business; 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 D&P business and CJWS. We also use Adjusted EBITDA in planning our capital allocation to sustain production levels and determining our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility (defined below in Liquidity and Capital Resources). Adjusted EBITDA is a non-GAAP financial measure that we define as earnings before interest expense; income taxes; depreciation, depletion, and amortization ("DD&A"); derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and unusual and infrequent items. See "Management's Discussion and Analysis—Non-GAAP Financial Measures" for reconciliation of Adjusted EBITDA to net (loss) income, our most directly comparable financial measure calculated and presented in accordance with GAAP.

Shareholder Returns

Commencing in 2022, we implemented a shareholder return model based on our Discretionary Free Cash Flow, which is a non-GAAP measure that we define as cash flow from operations less regular fixed dividends and the capital needed to hold production flat (see "Management's Discussion and Analysis—Non-GAAP Financial Measures" for reconciliation of Discretionary Free Cash Flow to cash provided by operating activities, our most directly comparable financial measure calculated and presented in accordance with GAAP). Under the shareholder return model, we intend to allocate a significant portion of the Discretionary Free Cash Flow generated each quarter to pay variable quarterly cash dividends. In May 2022, we declared our first variable dividend payment of $0.13 per share based on Discretionary Free Cash Flow generated in the first quarter of 2022, and in July 2022, we declared a variable dividend payment of $0.56 per share based on Discretionary Free Cash Flow generated in the second quarter of 2022. Under the shareholder return model, remaining Discretionary Free Cash Flow is expected to be allocated to fund opportunistic debt repurchases, opportunistic growth (including from our extensive inventory of drilling opportunities), advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention.

Our focus on shareholder returns is also demonstrated through our performance-based restricted stock awards, which are based on the Company's average cash returned on invested capital and total stockholder return on both a relative and absolute basis. Our 2022 short-term incentive plan also includes Discretionary Free Cash Flow performance goals.

Operating Expenses

Overall, operating expense is used by management as a measure of the efficiency with which operations are performing. With respect to our D&P business, we define operating expenses as lease operating expenses, electricity generation expenses, transportation expenses, and marketing expenses, offset by the third-party revenues generated by electricity, transportation and marketing activities, as well as the effect of derivative settlements (received or paid) for gas purchases. Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Taxes other than income taxes and costs of services are excluded from operating expenses. Marketing revenues represent sales of natural gas purchased from and sold to third parties. The electricity, transportation and marketing activity related revenues are viewed and treated internally as a reduction to operating costs when tracking and analyzing the economics of development projects and the efficiency of our hydrocarbon recovery. Additionally, we strive to minimize the variability of our fuel gas costs for our California steam operations with gas hedges, as well as contracts for the transportation of fuel gas from the Rockies which has historically been cheaper than the California markets.

Environmental, Health & Safety (EH&S)

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

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

General and Administrative Expenses

We monitor our cash general and administrative expenses as a measure of the efficiency of our overhead activities and less than 10% of such costs are capitalized, which we believe is significantly less than industry norms. Such expenses are a key component of the appropriate level of support our corporate and professional team provides to the development of our assets and our day-to-day operations.

Production

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

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. Oil and gas prices, including the differentials between the relevant benchmarks and the prices we receive for our oil and natural gas production in our D&P business, have fluctuated, and may continue to fluctuate, significantly as a result of numerous market-related variables, including geopolitical and global economic conditions and third-party transportation and market takeaway infrastructure capacity. While oil prices have significantly improved in 2022 relative to the lows experienced in 2020 and recoveries through 2021, they are still subject to volatility. We utilize derivatives to hedge a portion of our forecasted oil and gas production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices; our 2021 RBL Facility (defined below in Liquidity and Capital Resources) also has hedging requirements.

Our well servicing and abandonment business is dependent on expenditures of oil and gas companies, which tend to fluctuate in line with the volatility of commodity prices. However, 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. Additionally, our customers' requirements to plug and abandon wells are largely driven by regulatory requirements which are not dependent on commodity prices.

The COVID-19 pandemic resulted in a severe decrease in demand for oil, which created significant volatility and uncertainty in the oil and gas industry during 2020 and 2021. When combined with an excess supply of oil and related products, oil prices declined significantly in the first half of 2020. Although there has been some increasing volatility, overall oil prices have steadily improved since the lows experienced in 2020, in line with increasing demand despite the ongoing pandemic and uncertainties surrounding the COVID-19 variants. Oil and natural gas prices increased significantly during 2022, reaching a high of $123 during the second quarter, primarily due to global supply and demand imbalances. Brent prices were 14% and 62% higher for the three months ended June 30, 2022 as compared to the three months ended March 31, 2022 and June 30, 2021, respectively. Currently, global oil inventories are low relative to historical levels and supply increases from OPEC+ and other oil producing nations are not expected to be sufficient to meet forecasted oil demand growth for the next few years. It is believed that many OPEC+ countries will be unable to increase their production levels or even produce at expected levels due to their lack of capital investments in developing incremental oil supplies over the past few years. Furthermore, sanctions and import bans on Russian oil have been implemented by various countries in response to the war in Ukraine, further impacting global oil supply. Still, oil and natural gas prices have recently declined from the highs experienced in second quarter of 2022 and could decline further with any decrease in demand due to, among other things, uncertainty and volatility from global supply chain disruptions attributable to the pandemic, the ongoing conflict in Ukraine, international sanctions, speculation as to future actions by OPEC+, developing COVID-19 variants and the potential for a widespread COVID-19 outbreak, higher gas prices, increasing inflation and government efforts to reduce inflation, and possible changes in the overall health of the global economy, including a prolonged recession. Further, the volatility in oil and natural gas prices could accelerate a transition away from fossil fuels, resulting in reduced demand over the longer term. To what extent these and other external factors (such as government action with respect to climate change regulation) ultimately impact our future business, liquidity, financial condition, and results of operations is highly uncertain and dependent on numerous factors, including future developments, that are not within our control and cannot be accurately predicted.

Commodity Pricing and Differentials

Our revenue, costs, profitability, shareholder returns and future growth are highly dependent on the prices we receive for our oil and natural gas production, as well as the prices we pay for our natural gas purchases, which are affected by a variety of factors in Part I, Item 1A. “Risk Factors” in our Annual Report. We utilize derivatives to hedge a portion of our forecasted oil and gas production and gas purchases to reduce exposure to fluctuations in oil and natural gas prices.

Average oil prices, as noted below, were higher for the three months ended June 30, 2022 compared to the three months ended March 31, 2022 and June 30, 2021. Though the California market generally receives Brent-influenced pricing, California oil prices are determined ultimately by local supply and demand dynamics, including third-party transportation and market takeaway infrastructure capacity.

In California, the price we pay for fuel gas purchases is generally based on the Kern, Delivered Index, which was as high as $9.69 per mmbtu and as low as $5.15 per mmbtu during the second quarter of 2022, while we paid an average of $7.30 per mmbtu in this period.

The following table presents the average Brent, WTI, Kern, Delivered, and Henry Hub prices for the three months ended June 30, 2022, March 31, 2022 and June 30, 2021 and for the six months ended June 30, 2022 and June 30, 2021:

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	June 30, 2022	June 30, 2021
Oil (bbl) – Brent	$ 111.98	$ 97.90	$ 69.08	$ 104.94	$ 65.23
Oil (bbl) – WTI	$ 108.71	$ 94.54	$ 66.03	$ 101.67	$ 61.95
Natural gas (mmbtu) – Kern, Delivered	$ 7.36	$ 4.83	$ 3.23	$ 6.10	$ 5.60
Natural gas (mmbtu) – Henry Hub	$ 7.50	$ 4.67	$ 2.95	$ 6.08	$ 3.22

As mentioned above, California oil prices are Brent-influenced as California refiners import approximately 70% of the state's demand from OPEC+ countries and other waterborne sources. Without the higher costs and potential environmental impact associated with importing crude via rail or supertanker, we believe our in-state production and low-cost crude transportation options, coupled with Brent-influenced pricing, in appropriate oil price environments, should continue to allow us to realize positive cash margins in California over the cycle.

Utah oil prices have historically traded at a discount to WTI as the local refineries are designed for Utah's unique oil characteristics and the remoteness of the assets makes access to other markets logistically challenging. However, we have high operational control of our existing acreage, which provides significant upside for additional vertical and or horizontal development and recompletions.

Natural gas prices and their differentials are strongly affected by local market fundamentals, availability of third-party transportation and market takeway infrastructure capacity from producing areas and seasonal impacts. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities than we produce and sell in the Rockies. In recent history, the California gas markets have generally had higher gas prices than the Rockies and the rest of the United States. Higher gas prices have a negative impact on our operating results. However, we mitigate a portion of this exposure by selling excess electricity from our cogeneration operations to third parties at prices linked to the price of natural gas. We also strive to minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of such gas purchases. In addition, we have entered into pipeline capacity agreements for the shipment of natural gas from the Rockies to our assets in California that help reduce our exposure to fuel gas purchase price fluctuations. Additionally, the negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce and sell in the Rockies.

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

Our earnings are also affected by the performance of our cogeneration facilities. These cogeneration facilities generate both electricity and steam for our properties and electricity for off-lease sales. While a portion of the electric output of our cogeneration facilities is utilized within our production facilities to reduce operating expenses, we also sell electricity produced by two of our cogeneration facilities under contracts with terms ending in December 2022 through December 2026. The most significant input and cost of the cogeneration facilities is natural gas. We generally receive significantly more revenue from these cogeneration facilities in the summer months, most notably in June through September, due to negotiated capacity payments we receive.

Regulatory Matters

Like other companies in the oil and gas industry, both our D&P business and CJWS are subject to complex and stringent federal, state, and local laws and regulations, and California, where most of our operations and assets are located, is one of the most heavily regulated states in the United States with respect to oil and gas operations. A combination of federal, state and local laws and regulations govern most aspects of our activities in California. Collectively, the effect of the existing laws and regulations is to potentially 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, and reduce the amount of oil and natural gas that we can produce from our wells below levels that would otherwise be possible. Additionally, the regulatory burden on the industry increases our costs and consequently may have an adverse effect upon operations, capital expenditures, earnings and our competitive position. Violations and liabilities with respect to these laws and regulations could result in significant administrative, civil, or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and future prospects. 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.

Our oil and gas operations in California are subject to compliance with the California Environmental Quality Act (“CEQA”), and we cannot receive certain permits and other approvals required for our operations until we have demonstrated compliance with CEQA. There have been a number of developments at both the California state and local levels that have resulted in delays in the issuance of new drilling permits for oil and gas activities in Kern County where all of our California assets are located, as well as a more time- and cost- intensive permitting process. Most notably, in Kern County, we historically have satisfied CEQA by complying with the local oil and gas ordinance, which was supported by an Environmental Impact Report (an “EIR”) covering oil and gas operations in Kern County (“Kern County EIR”). In 2020, a lawsuit was filed challenging the Kern County EIR, and subsequently the California Fifth District Court of Appeals issued a ruling invalidating a portion of the Kern County EIR until Kern County made certain revisions to the Kern County EIR and recertified it (“Kern County Ruling”). To address the Kern County Ruling, Kern County prepared a supplemental EIR which was approved by the Kern County Board of Supervisors in March 2021. Following further challenges by plaintiffs, a Kern County Superior Court judge suspended use of the Kern County EIR as supplemented, stopping the issuance of new oil and gas permits by Kern County (the “Kern County Permit Suspension”) in October 2021, pending a determination by the Kern County Superior Court that the Kern County EIR complied with the CEQA requirements. On June 7, 2022, while the Kern County Superior Court ruled in favor of Kern County on some aspects, it found that the supplemental Kern County EIR still failed to meet the minimum requirements of CEQA. The court instructed the parties to meet in mid-July to discuss how Kern County will resolve these violations. While the resolution of these issues is pending, the Kern County Permit Suspension remains in effect. We cannot predict the outcome of this case or whether it will result in the imposition of more onerous permit requirements or other requirements or restrictions on land use and exploration and production activities, or to what extent it may impact our business, financial condition, results of operations and future prospects.

Importantly, neither the Kern County Ruling nor the Kern County Permit Suspension invalidated existing permits and our plans and operations have not been materially impacted to date. Until Kern County is able to resolve the challenges regarding the sufficiency of the Kern County EIR and resume the ability to issue permits, our ability to obtain new permits and approvals to enable our future plans in Kern County requires demonstrating compliance with CEQA to CalGEM. Demonstrating CEQA compliance without being able to reference the Kern County EIR or another CEQA-compliant EIR is a more technical, time and cost intensive process and may, among other things, require that we conduct an extensive environmental impact review. As a result, we together with other Kern County operators have experienced delays in the issuance of permits for new wells by CalGEM, as well as a more time- and cost- intensive permitting process for new wells. We have not experienced delays in the issuance of permits for the workover of existing wells or other activities re-using existing well bores, for which the environmental review is expedited because the well already exists.

We have submitted permit applications for the new wells contemplated by our 2022 capital development However, due to insufficient permit inventory, the execution of our 2022 capital development program in the second quarter ultimately required an increase in workover and other activities re-using existing well bores and that increased production from existing producing wells (referred to as our “base production”), and fewer new wells drilled. Our plans for the remainder of the year will depend on whether and when we receive permits to drill new wells, as well as other key approvals (such as UIC permits to support water disposal) required to support planned activities. If we are unable to timely obtain those permits or approvals, our planned 2022 production could be adversely impacted and we may need to modify our 2022 capital development program and reduce our planned capital expenditures or deploy that capital to other activities. However, at this time we do not expect our planned 2022 production or results of operations to be materially impacted even if we are unable to timely obtain those permits and approvals because we currently believe we can continue to offset planned new wells with increased production from workover and other activities re-using existing well bores, as well as from our base production through field optimization initiatives. At this time we expect that most (over 90%) of our planned 2022 production will come from our base production, with the remainder from workovers and other activities related to existing well bores as well as new wells drilled during the year.”

Seasonality

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

Natural gas prices fluctuate based on seasonal and other market-related impacts. For example, natural gas prices increased significantly in the first and second quarters of 2022 reflecting a premium driven by European instability which brought new demand for domestic production as a way to replace natural gas previously produced by Russia, as well as lower storage levels. We purchase significantly more gas than we sell to generate steam and electricity in our cogeneration facilities for our production activities in our D&P business. As a result, our key exposure to gas prices is in our costs. We mitigate a substantial portion of this exposure by selling excess electricity from our cogeneration operations to third parties. The pricing of these electricity sales is closely tied to the purchase price of natural gas. These sales are generally higher in the summer months as they include seasonal capacity amounts. We also hedge a significant portion of the gas we expect to consume and in 2021 we entered into new pipeline capacity agreements for the shipment of natural gas from the Rockies to our operations in California to help limit our exposure to fuel gas purchase price fluctuations.

Capital Expenditures

For the three and six months ended June 30, 2022, our consolidated capital expenditures were approximately $34 million and $62 million, respectively, on an accrual basis including capitalized overhead and interest and excluding acquisitions and asset retirement spending. Approximately 54% and 35% of capital expenditures for the six months ended June 30, 2022 was directed to California oil and Utah operations, respectively.

Our 2022 capital expenditure budget for D&P operations and corporate activities is approximately $125 to $135 million, excluding $8 million for C&J Well Services, the planned use of which is expected to keep our annual production relatively flat to 2021 after taking into account the impact of acquisitions and divestitures completed earlier this year. We currently anticipate our capital expenditures will be at the lower end of the guidance range because the execution of our 2022 capital development program now reflects an increase in workover and other activities re-using existing well bores and drilling fewer new wells due to delays in permit issuance by CalGEM. We expect oil production will be approximately 92% of total production volume in 2022, compared to 88% in 2021. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2022 capital development program with cash flow from operations.

The amount and timing of capital expenditures are within our control and subject to our discretion, and due to the speed with which we are able to drill and complete our wells in California, capital may be adjusted quickly during the year depending on numerous factors, including permit inventory to support planned activities, commodity prices, storage and third-party transportation constraints, supply/demand considerations and attractive rates of return. We believe it is important to retain the flexibility to defer planned capital expenditures and may do so based on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGLs, the receipt and timing of required regulatory permits and approvals, the availability of necessary equipment, infrastructure and capital, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners, as well as general market conditions. Any postponement or elimination of our development program could result in a reduction of proved reserves volumes and materially affect our business, financial condition and results of operations.

Additionally and not included in the capital expenditures noted above, for the full year 2022, we plan to spend approximately $21 million to $24 million on plugging and abandonment activities, including 280 to 320 wells and satisfying our annual obligations under the California Idle Well Management Program. We spent approximately $6 million and $11 million for plugging and abandonment activities in the three months and six months ended June 30, 2022, respectively. Our well servicing and abandonment segment expects to plug and abandon approximately 2,500 to 3,000 wells for their third party customers in 2022, helping to safely address the environmental hazards and others risk from California’s number of idle wells.

Summary by Area

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

($ in thousands, except prices)	California (San Joaquin and Ventura basins)[3] Three Months Ended June 30, 2022	California Three Months Ended March 31, 2022	California Three Months Ended June 30, 2021
Oil, natural gas and natural gas liquids sales	$ 204,706	$ 186,252	$ 129,128
Operating income[1]	$ 63,608	$ 60,162	$ 11,413
Depreciation, depletion, and amortization (DD&A)	$ 34,074	$ 35,786	$ 35,174
Average daily production (mboe/d)	21.0	22.2	21.7
Production (oil % of total)	100 %	100 %	100 %
Realized sales prices:			
Oil (per bbl)	$ 107.31	$ 93.16	$ 65.37
NGLs (per bbl)	$ —	$ —	$ —
Gas (per mcf)	$ —	$ —	$ —
Capital expenditures[2]	$ 18,672	$ 14,622	$ 31,303

($ in thousands, except prices)	Utah (Uinta basin) Three Months Ended June 30, 2022	Utah March 31, 2022	Utah June 30, 2021	Colorado (Piceance basin)[4] Three Months Ended June 30, 2022	Colorado March 31, 2022	Colorado June 30, 2021
Oil, natural gas and natural gas liquids sales	$ 35,338	$ 23,038	$ 16,199	$ —	$ 1,056	$ 2,438
Operating income[1]	$ 20,579	$ 11,173	$ 6,736	$ —	$ 610	$ 1,121
Depreciation, depletion, and amortization (DD&A)	$ 964	$ 803	$ 630	$ —	$ 9	$ 38
Average daily production (mboe/d)	5.2	4.1	4.4	—	0.4	1.2
Production (oil % of total)	57 %	53 %	52 %	— %	— %	2 %
Realized sales prices:						
Oil (per bbl)	$ 94.47	$ 83.02	$ 58.55	$ —	$ 89.41	$ 56.05
NGLs (per bbl)	$ 56.47	$ 47.03	$ 29.61	$ —	$ —	$ —
Gas (per mcf)	$ 7.35	$ 5.93	$ 3.30	$ —	$ 5.12	$ 3.53
Capital expenditures[2]	$ 11,563	$ 9,752	$ 9,162	$ —	$ —	$ —

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

(2) Excludes corporate capital expenditures.

(3) Our Placerita properties, in the Ventura basin, were divested in October 2021.

(4) Our properties in Colorado were in the Piceance basin, all of which were divested in January 2022.

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, 2022	March 31, 2022	June 30, 2021
Average daily production:[1]			
Oil (mbbl/d)	24.0	24.4	24.0
Natural Gas (mmcf/d)	11.0	11.5	17.5
NGL (mbbl/d)	0.4	0.4	0.4
Total (mboe/d)[2]	26.2	26.7	27.3
Total Production:			
Oil (mbbl)	2,182	2,198	2,183
Natural gas (mmcf)	999	1,037	1,595
NGLs (mbbl)	37	35	36
Total (mboe)[2]	2,386	2,406	2,485
Weighted-average realized sales prices:			
Oil without hedges ($/bbl)	$ 105.70	$ 92.25	$ 64.72
Effects of scheduled derivative settlements ($/bbl)	$ (21.92)	$ (15.38)	$ (18.33)
Oil with hedges ($/bbl)	$ 83.78	$ 76.87	$ 46.39
Natural gas ($/mcf)	$ 7.35	$ 5.77	$ 3.39
NGL ($/bbl)	$ 56.47	$ 47.03	$ 29.61
Average Benchmark prices:			
Oil (bbl) – Brent	$ 111.98	$ 97.90	$ 69.08
Oil (bbl) – WTI	$ 108.71	$ 94.54	$ 66.03
Natural gas (mmbtu) – Kern, Delivered[3]	$ 7.36	$ 4.83	$ 3.23
Natural gas (mmbtu) – Henry Hub[4]	$ 7.50	$ 4.67	$ 2.95

(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, 2022, the average prices of Brent oil and Henry Hub natural gas were $111.98 per bbl and $7.50 per mmbtu.

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

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

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

	Three Months Ended		
	June 30, 2022	March 31, 2022	June 30, 2021
Average daily production (mboe/d):[1]			
California[2]	21.0	22.2	21.7
Utah	5.2	4.1	4.4
Colorado[3]	—	0.4	1.2
Total average daily production	26.2	26.7	27.3

(1) Production represents volumes sold during the period.

(2) In October 2021, we divested our Placerita (California) properties, exclusively oil production, which had average production of 0.9 mbbl/d in the second quarter 2021.

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

Average daily production for the second quarter 2021 included properties that have since been divested, specifically, Placerita properties in California and Piceance properties, which were our only assets in Colorado. The combined production from these properties was 2.1 mboe/d in the second quarter 2021, 0.4 mboe/d in the first quarter 2022 and none in the second quarter 2022. Additionally, the first and second quarters of 2022 included 0.3 mboe/d and 1.1 mboe/d, respectively from Antelope Creek (Utah) properties we acquired in February 2022.

On a sequential basis, when excluding the volumes from these acquisitions and divestitures, our average daily production decreased by 0.9 mboe/d for the three months ended June 30, 2022, compared to the three months ended March 31, 2022. Our California production was 21.0 mboe/d for the second quarter of 2022, a decrease of 1.2 mboe/d from the first quarter 2022, which was largely due to offset wells being shut in during planned drilling, workover and abandonment activities. Our Utah production increased as a result of the drilling program during the first and second quarters of 2022.

On a comparable basis, when excluding the production from these transactions, our production was up slightly in California and essentially flat company-wide when comparing the second quarter of 2022 to the second quarter of 2021.

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, 2022	June 30, 2021
Average daily production:(1)		
Oil (mbbl/d)	24.2	23.9
Natural Gas (mmcf/d)	11.3	17.2
NGL (mbbl/d)	0.4	0.4
Total (mboe/d)(2)	26.5	27.2
Total Production:		
Oil (mbbl)	4,379	4,334
Natural gas (mmcf)	2,037	3,113
NGLs (mbbl)	72	66
Total (mboe)(2)	4,791	4,919
Weighted-average realized sales prices:		
Oil without hedges ($/bbl)	$ 98.95	$ 60.83
Effects of scheduled derivative settlements ($/Bbl)	$ (18.64)	$ (15.22)
Oil with hedges ($/Bbl)	$ 80.31	$ 45.61
Natural gas ($/mcf)	$ 6.55	$ 5.62
NGL ($/bbl)	$ 51.90	$ 28.30
Average Benchmark prices:		
Oil (bbl) – Brent	$ 104.94	$ 65.23
Oil (bbl) – WTI	$ 101.67	$ 61.95
Gas (mmbtu) – Kern, Delivered(3)	$ 6.10	$ 5.60
Natural gas (mmbtu) – Henry Hub(4)	$ 6.08	$ 3.22

(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, 2022, the average prices of Brent oil and Henry Hub natural gas were $104.94 per bbl and $6.08 per mmbtu respectively.

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

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

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

	Six Months Ended	
	June 30, 2022	June 30, 2021
Average daily production (mboe/d):[(1)]		
California[(2)]	21.6	21.8
Utah	4.7	4.2
Colorado[(3)]	0.2	1.2
Total average daily production	26.5	27.2

(1) Production represents volumes sold during the period.

(2) In October 2021, we divested our Placerita (California) properties, exclusively oil production, which had average production of 0.9 mbbl/d in the second quarter 2021.

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

Average daily production for the six months ended June 30, 2022 included 0.7 mboe/d of production from the Antelope Creek (Utah) asset acquired in the first quarter of 2022 and 0.2 mboe/d of production from the Piceance (Colorado) asset, which was divested in the first quarter of 2022. The six months ended June 30, 2021 included 1.2 mboe/d of production from the Colorado assets, as well as 0.9 mboe/d of production from the Placerita asset in California, which was divested in the fourth quarter of 2021.

On a comparable basis, when excluding the volumes from these acquisitions and divestitures, California produced 21.6 mboe/d for the six months ended June 30, 2022, a 3% increase compared to the six months ended June 30, 2021. We drilled 43 wells in California in the first half of 2022, of which thirty-one were producing wells, eight were delineation and four were observation wells. When excluding the volumes from these transactions, our production in Utah was essentially flat for the six months ended June 30, 2022 compared to the six months ended June 30, 2021.

Results of Operations

Three Months Ended June 30, 2022 compared to Three Months Ended March 31, 2022.

	Three Months Ended			
	June 30, 2022	March 31, 2022	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 240,071	$ 210,351	$ 29,720	14 %
Service revenue	46,178	39,836	6,342	16 %
Electricity sales	7,419	5,419	2,000	37 %
Losses on oil and gas sales derivatives	(40,658)	(161,858)	121,200	(75)%
Marketing and other revenues	120	334	(214)	(64)%
Total revenues and other	$ 253,130	$ 94,082	$ 159,048	169 %

Revenues and Other

Oil, natural gas and NGL sales increased by $30 million, or 14%, to approximately $240 million for the three months ended June 30, 2022, compared to the three months ended March 31, 2022. The increase was driven by $29 million higher unhedged oil prices and $2 million higher gas prices, partially offset by $1 million lower oil volumes.

Service revenue consisted entirely of revenue from the well servicing and abandonment business. Service revenue increased by $6 million or 16% to approximately $46 million in the first quarter 2022, largely due to seasonal impact and rate increases established to offset a portion of cost inflation.

Electricity sales represent sales to utilities and increased $2 million, or 37%, to approximately $7 million for the three months ended June 30, 2022 compared to the three months ended March 31, 2022. This increase was largely due to higher unit sales prices driven by higher natural gas prices.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. Our settlement loss for the three months ended June 30, 2022 was $48 million and the loss for the three months ended March 31, 2022 was $34 million. The quarter-over-quarter increase in settlement losses was driven by higher index prices relative to the fixed prices of settled positions and additional notional volumes of 4,000 bbls per day. The average derivative fixed price increased $7 per bbl and the associated index price increased approximately $13 per bbl, both compared to the the first quarter of 2022. The mark-to-market non-cash gain of $7 million for the three months ended June 30, 2022 was due to the average market price being closer to, although higher than, the fixed price at the end of the quarter. The mark-to-market non-cash loss of $128 million for the three months end March 31, 2022 was due to an increase in the difference between the the average future price and the derivative fixed price.

Marketing and other revenues, which included third-party marketing activities, were not material for the three months ended June 30, 2022 and March 31, 2022.

	Three Months Ended			
	June 30, 2022	March 31, 2022	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 72,455	$ 63,124	$ 9,331	15 %
Costs of services	36,709	33,472	3,237	10 %
Electricity generation expenses	6,122	4,463	1,659	37 %
Transportation expenses	1,108	1,158	(50)	(4)%
Marketing expenses	—	299	(299)	(100)%
General and administrative expenses	23,183	22,942	241	1 %
Depreciation, depletion and amortization	38,055	39,777	(1,722)	(4)%
Taxes, other than income taxes	11,214	6,605	4,609	70 %
Losses (gains) on natural gas purchase derivatives	10,661	(29,054)	39,715	n/a
Other operating expenses	353	3,769	(3,416)	(91)%
Total expenses and other	199,860	146,555	53,305	36 %
Other (expenses) income:				
Interest expense	(7,729)	(7,675)	(54)	1 %
Other, net	(42)	(13)	(29)	223 %
Total other (expenses) income	(7,771)	(7,688)	(83)	1 %
Income (loss) before income taxes	45,499	(60,161)	105,660	(176)%
Income tax expense (benefit)	2,145	(3,351)	5,496	(164)%
Net income (loss)	$ 43,354	$ (56,810)	$ 100,164	(176)%
Expenses per boe:[1]				
Lease operating expenses	$ 30.37	$ 26.25	$ 4.12	16 %
Electricity generation expenses	2.57	1.86	0.71	38 %
Electricity sales[1]	(3.11)	(2.25)	(0.86)	38 %
Transportation expenses	0.46	0.48	(0.02)	(4)%
Transportation sales[1]	(0.05)	(0.02)	(0.03)	150 %
Marketing expenses	—	0.13	(0.13)	(100)%
Marketing revenues[1]	—	(0.12)	0.12	(100)%
Derivatives settlements received for gas purchases[1]	(4.27)	(0.69)	(3.58)	519 %
Total operating expenses	$ 25.97	$ 25.64	$ 0.33	1 %
Total unhedged operating expenses[2]	$ 30.24	$ 26.33	$ 3.91	15 %
Total non-energy operating expenses[3]	$ 16.10	$ 13.58	$ 2.52	19 %
Total energy operating expenses[4]	$ 9.87	$ 12.06	$ (2.19)	(18)%
General and administrative expenses[5]	$ 9.72	$ 9.54	$ 0.18	2 %
Depreciation, depletion and amortization	$ 15.95	$ 16.53	$ (0.58)	(4)%
Taxes, other than income taxes	$ 4.70	$ 2.74	$ 1.96	72 %

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

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

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.77 per boe and $1.62 per boe for the three months ended June 30, 2022 and March 31, 2022, respectively.

Expenses and Other

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

Operating expenses are defined above in “How We Plan and Evaluate Operations”, which include electricity, marketing and transportation revenues. On a hedged basis, operating expenses increased by $0.33 per boe, or 1%, to $25.97 for the second quarter of 2022 compared to the first quarter of 2022. During the second quarter, non-energy operating expenses increased due to higher workover and field monitoring activity associated with our field optimization program, and well and facility maintenance expenses. A portion of these higher costs were driven by inflation. Energy operating expense decreased in the second quarter due to lower hedged fuel prices and higher electricity sales, compared to the first quarter of 2022.

Unhedged lease operating expenses per boe increased by 16%, or $4.12, to $30.37 for the three months ended June 30, 2022, compared to $26.25 per boe for the three months ended March 31, 2022, for the same reasons noted for non-energy expense.

Cost of services in 2022 consisted entirely of costs from the well servicing and abandonment business. Cost of services increased by $3 million, or 10%, compared to $37 million in the second quarter of 2022, mainly due to employee and fuel cost inflation.

Electricity generation expenses increased approximately 38% to $2.57 per boe for the three months ended June 30, 2022, compared to $1.86 per boe for the three months ended March 31, 2022 due to higher natural gas fuel costs. Fuel costs exclude the effects of natural gas derivative settlements mentioned elsewhere.

Gains and losses on natural gas purchase derivatives resulted in an $11 million loss for the three months ended June 30, 2022 and a gain of $29 million in the three months ended March 31, 2022. Settlement gains for the three months ended June 30, 2022 and March 31, 2022 were $10 million, or $4.27 per boe, and $2 million, or $0.69 per boe, respectively, and increased due to higher index prices relative to the fixed prices of settled positions in the second quarter of 2022 than that of the first quarter. The mark-to-market valuation loss was $21 million for the three months ended June 30, 2022 and a gain of $27 million for the three months ended March 31, 2022, due to lower futures prices relative to the derivative fixed prices in the second quarter compared to the first quarter.

Transportation expenses are comparable for the periods presented.

Marketing expenses, which included third-party marketing activities were not material for the three months ended June 30, 2022 and March 31, 2022.

General and administrative expenses were flat at $23 million for the three months ended June 30, 2022 and the three months ended March 31, 2022. For the three months ended June 30, 2022 and March 31, 2022, general and administrative expenses included non-cash stock compensation costs of approximately $4.3 million and $3.7 million, respectively. We incurred no non-recurring costs for the three months ended June 30, 2022 and approximately $0.2 million in expenses related to acquisition activity for the three months ended March 31, 2022. Less than 10% of our overhead is capitalized and thus excluded from general and administrative expenses.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, were $19 million for the three months ended June 30, 2022, and was flat compared to the three months ended March 31, 2022. See "—Non-GAAP Financial Measures" for a reconciliation of adjusted general and administrative expense to general and administrative expenses, the most directly comparable financial measures calculated and presented in accordance with GAAP.

DD&A was $38 million, or 4%, lower for the three months ended June 30, 2022 compared to the three months ended March 31, 2022. The decrease was a result of slightly lower production in the D&P segment.

Taxes, Other Than Income Taxes

	Three Months Ended			
	June 30, 2022	March 31, 2022	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.54	$ 1.26	$ 0.28	22 %
Ad valorem and property taxes	1.49	1.51	(0.02)	(1)%
Greenhouse gas allowances	1.67	(0.03)	1.70	(5,667)%
Total taxes other than income taxes	$ 4.70	$ 2.74	$ 1.96	72 %

Taxes, other than income taxes, increased in the three months ended June 30, 2022 by $1.96 per boe, or 72%, to $4.70. Severance taxes were higher in the second quarter of 2022 due to higher revenue in Utah. The second quarter 2022 greenhouse gas ("GHG") amount was a result of higher mark-to-market prices as that market returned to more normal levels compared to the first quarter of 2022.

Other Operating Expenses

For the three months ended June 30, 2022, other operating expenses decreased $3 million to $0.4 million. The first quarter of 2022 consisted of over $2 million of royalty audit charges incurred prior to our emergence and restructuring in 2017, and over $1 million loss on the divestiture of the Piceance properties.

Interest Expense

Interest expense was relatively flat at $8 million for each of the three months ended June 30, 2022 and March 31, 2022.

Income Taxes

Our effective tax rate was approximately 5% for the three months ended June 30, 2022, and for the three months ended March 31, 2022.

Three Months Ended June 30, 2022 compared to Three Months Ended June 30, 2021.

	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 240,071	$ 147,775	$ 92,296	62 %
Service revenue	46,178	—	46,178	100 %
Electricity sales	7,419	6,888	531	8 %
Losses on oil and gas sales derivatives	(40,658)	(55,653)	14,995	(27)%
Marketing and other revenues	120	239	(119)	(50)%
Total revenues and other	$ 253,130	$ 99,249	$ 153,881	155 %

Revenues and Other

Oil, natural gas and NGL sales increased by $92 million, or 62%, to approximately $240 million for the three months ended June 30, 2022 when compared to the three months ended June 30, 2021. This variance was principally the result of higher unhedged commodity prices.

Service revenue in the first quarter 2022 was $46 million and there was no corresponding revenue in the first quarter 2021 as we acquired this business on October 1, 2021.

Electricity sales represent sales to utilities, and increased by approximately $1 million, or 8%, to approximately $7 million for the three months ended June 30, 2022 when compared to the three months ended June 30, 2021. The increase was largely due to higher unit sales price driven by higher natural gas prices, partially offset by lower unit sales volumes driven by the sale of our Placerita asset, which included our largest electricity-generating cogeneration facility (“cogen”), in the fourth quarter 2021. Over the last three years the Placerita cogen accounted for approximately 41% of our electrical sales.

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, 2022 and the three months ended June 30, 2021 were $48 million and $40 million, respectively. The quarter-over-quarter increases in settlement losses were driven by higher oil prices relative to our derivative fixed prices in the second quarter of 2022 than that of the same period in 2021. Notional volumes were 15 mbbl/d in the second quarter 2022 and 19 mbbls/d in the second quarter 2021. The mark-to-market non-cash gain of $7 million for the three months ended June 30, 2022 was due to the average market price being closer to, although higher than, the fixed price at the end of the quarter. The mark-to-market non-cash loss of $16 million for the three months ended June 30, 2021 was due to an increase in the difference between the the average future price and the derivative fixed price. Because we are the floating price payer on these swaps, generally, period to period decreases (increases) in the associated price index create valuation gains (losses).

Marketing and other revenues were not material for the three months ended were slightly lower the three June 30, 2022 and June 30, 2021.

	Three Months Ended June 30, 2022	2021	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 72,455	$ 45,543	$ 26,912	59 %
Costs of services	36,709	—	36,709	100 %
Electricity generation expenses	6,122	4,712	1,410	30 %
Transportation expenses	1,108	1,757	(649)	(37)%
Marketing expenses	—	44	(44)	(100)%
General and administrative expenses	23,183	16,065	7,118	44 %
Depreciation, depletion and amortization	38,055	35,850	2,205	6 %
Taxes, other than income taxes	11,214	11,603	(389)	(3)%
Losses (gains) on natural gas purchase derivatives	10,661	(11,639)	22,300	n/a
Other operating expenses	353	42	311	740 %
Total expenses and other	199,860	103,977	95,883	92 %
Other (expenses) income:				
Interest expense	(7,729)	(8,217)	488	(6)%
Other, net	(42)	(8)	(34)	425 %
Total other (expenses) income	(7,771)	(8,225)	454	(6)%
Income (loss) before income taxes	45,499	(12,953)	58,452	(451)%
Income tax expense (benefit)	2,145	(72)	2,217	(3,079)%
Net income (loss)	$ 43,354	$ (12,881)	$ 56,235	437 %
Expenses per boe:[1]				
Lease operating expenses	$ 30.37	$ 18.33	$ 12.04	66 %
Electricity generation expenses	2.57	1.90	0.67	35 %
Electricity sales[1]	(3.11)	(2.77)	(0.34)	12 %
Transportation expenses	0.46	0.70	(0.24)	(34)%
Transportation sales[1]	(0.05)	(0.05)	—	— %
Marketing expenses	—	0.02	(0.02)	(100)%
Marketing revenues[1]	—	(0.05)	0.05	(100)%
Derivatives settlements received for gas purchases[1]	(4.27)	(0.77)	(3.50)	455 %
Total operating expenses	$ 25.97	$ 17.31	$ 8.66	50 %
Total unhedged operating expenses[2]	$ 30.24	$ 18.08	$ 12.16	67 %
Total non-energy operating expenses[3]	$ 16.10	$ 12.71	$ 3.39	27 %
Total energy operating expenses[4]	$ 9.87	$ 4.60	$ 5.27	115 %
General and administrative expenses[5]	$ 9.72	$ 6.46	$ 3.26	50 %
Depreciation, depletion and amortization	$ 15.95	$ 14.43	$ 1.52	11 %
Taxes, other than income taxes	$ 4.70	$ 4.67	$ 0.03	1 %

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

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

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.77 per boe and $1.11 per boe for the three months ended June 30, 2022 and June 30, 2021, respectively.

Expenses and Other

On a hedged basis, operating expenses, increased by 50%, or $8.66 per boe, to $25.97 per boe for the second quarter of 2022 compared to $17.31 per boe for the second quarter of 2021. The increase was largely due to an increase in hedged fuel prices, as well as certain lease operating expenses.

Unhedged lease operating expenses were $30.37 per boe for the three months ended June 30, 2022, a 66% or $12.04 per boe increase compared to $18.33 for the three months ended June 30, 2021. Unhedged fuel costs for our California steam operations increased $8.32 per boe. Unhedged average fuel purchase price per mmbtu increased 121% in the second quarter of 2022 compared to the second quarter of 2021 and gas volumes purchased were down 9%. As expected, lease operating expenses increased, driven by higher well maintenance, field monitoring and workover activity associated with our field optimization program, as well as higher labor costs. A portion of these higher costs were driven by inflation.

Cost of services in the second quarter of 2022 were $37 million and there were no costs of services in the second quarter of 2021, as we acquired the well servicing and abandonment business on October 1, 2021.

Electricity generation expenses increased approximately 35% to $2.57 per boe for the three months ended June 30, 2022 from $1.90 per boe for the same period in 2021 due to higher natural gas costs, partially offset by the Placerita properties sale. Fuel costs included in electricity generation expenses exclude the effects of natural gas derivative settlements.

Gains and losses on natural gas purchase derivatives for the three months ended June 30, 2022 and June 30, 2021 resulted in a loss of $11 million and a gain of $12 million, respectively. Settlement gains for the three months ended June 30, 2022 were $10 million or $4.27 per boe compared to the settlement gain of $2 million or $0.77 per boe for the three months ended June 30, 2021, driven by higher gas prices. The mark-to-market valuation loss for the three months ended June 30, 2022 was $21 million compared to a $10 million gain for the same period in 2021. 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 decreased to $0.46 per boe for the three months ended June 30, 2022 compared to $0.70 per boe for the three months ended June 30, 2021, primarily due to the sale of our Piceance operations the first quarter of 2022.

Marketing expenses were not material for the three months ended June 30, 2022 and June 30, 2021.

General and administrative expenses increased $7 million, or 44%, to approximately $23 million for the three months ended June 30, 2022 compared to the three months ended June 30, 2021. For the three months ended June 30, 2022 and June 30, 2021, general and administrative expenses included non-cash stock compensation costs of approximately $4 million and $3 million, respectively. The second quarter of 2022 also included $3 million of general and administrative expenses from the well servicing and abandonment segment which had no corresponding amount in 2021 as we purchased CJWS in the fourth quarter of 2021.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, increased 46% to $19 million for the three months ended June 30, 2022 compared to $13 million for the three months ended June 30, 2021. The increase was primarily due to the acquisition of CJWS, as well as higher legal and other professional service expenses and employee costs.

DD&A for the second quarter of 2022 increased approximately $2 million to $38 million when compared to the first quarter of 2021 driven primarily by CJWS and slightly higher DD&A rates for the D&P segment, partially offset by lower production.

Taxes, Other Than Income Taxes

	Three Months Ended June 30,			
	2022	2021	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.54	$ 0.97	$ 0.57	59 %
Ad valorem and property taxes	1.49	1.99	(0.50)	(25)%
Greenhouse gas allowances	1.67	1.71	(0.04)	(2)%
Total taxes other than income taxes	$ 4.70	$ 4.67	$ 0.03	1 %

Taxes, other than income taxes increased 1% to $4.70 per boe for the three months ended June 30, 2022 compared to $4.67 per boe for the three months ended June 30, 2021. Severance taxes increased due to higher production and prices in Utah, while property taxes were lower due to the divestitures of Piceance and Placerita. GHG expense was lower due to lower emissions which resulted from the divestiture of Placerita and its cogeneration facility, more than offsetting higher mark-to-market prices at the end of the period.

Other Operating Expenses (Income)

Other operating expenses were comparable in the three months ended June 30, 2022 and June 30, 2021.

Interest Expense

Interest expense was comparable in the three months ended June 30, 2022 and June 30, 2021.

Income Taxes

Our effective tax rate was approximately 5% for the three months ended June 30, 2022 compared to 1% for the three months ended June 30, 2021. The rates were impacted by changes in the valuation allowance recorded against deferred tax assets.

Six Months Ended June 30, 2022 compared to Six Months Ended June 30, 2021.

	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	$ Change	% Change
	(in thousands)			
Revenues and other:				
Oil, natural gas and NGL sales	$ 450,422	$ 283,040	$ 167,382	59 %
Service revenue	86,014	—	86,014	100 %
Electricity sales	12,838	16,957	(4,119)	(24)%
Losses on oil and gas sales derivatives	(202,516)	(109,157)	(93,359)	86 %
Marketing and other revenues	454	2,610	(2,156)	(83)%
Total revenues and other	$ 347,212	$ 193,450	$ 153,762	79 %

Revenues and Other

Oil, natural gas and NGL sales increased by $167 million, or 59%, to approximately $450 million for the six months ended June 30, 2022 when compared to the six months ended June 30, 2021. The increase was driven by higher realized prices.

Service revenue consisted entirely of revenue from the well servicing and abandonment business we acquired on October 1, 2021, thus no prior period revenue.

Electricity sales, which represent sales to utilities, decreased $4 million, or 24%, to $13 million for the six months ended June 30, 2022 when compared to the six months ended June 30, 2021. The decrease was primarily due to reduced volumes from the late 2021 sale of a cogeneration facility which was part of the Placerita divestiture.

Gain or loss on oil and gas sales derivatives consists of settlement gains and losses and mark-to-market gains and losses. We had settlement losses of $82 million and $66 million for the for the six months ended June 30, 2022 and the six months ended June 30, 2021, 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, 2022 compared to the same period of 2021. Partially offsetting this effect, notional volumes decreased to 13 mbbl/d in the six months ended June 30, 2022 from 19 mbbl/d in the six months ended June 30, 2021. The mark-to-market non-cash loss of $121 million and $43 million for the six months ended June 30, 2022 and June 30, 2021, respectively, was due to higher futures prices relative to the derivative fixed prices at the end of their respective periods.

Marketing and other revenues were not material for the six months ended June 30, 2022 and June 30, 2021.

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	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	$ Change	% Change
	(in thousands, except expenses per boe)			
Expenses and other:				
Lease operating expenses	$ 135,579	$ 107,827	$ 27,752	26 %
Costs of services	70,181	—	70,181	100 %
Electricity generation expenses	10,585	12,360	(1,775)	(14)%
Transportation expenses	2,266	3,333	(1,067)	(32)%
Marketing expenses	299	2,271	(1,972)	(87)%
General and administrative expenses	46,125	33,135	12,990	39 %
Depreciation, depletion and amortization	77,832	69,690	8,142	12 %
Taxes, other than income taxes	17,819	21,160	(3,341)	(16)%
Gains on natural gas purchase derivatives	(18,393)	(39,369)	20,976	(53)%
Other operating expenses	4,122	841	3,281	390 %
Total expenses and other	346,415	211,248	135,167	64 %
Other (expenses) income:				
Interest expense	(15,404)	(16,702)	1,298	(8)%
Other, net	(55)	(151)	96	(64)%
Total other (expenses) income	(15,459)	(16,853)	1,394	(8)%
Loss before income taxes	(14,662)	(34,651)	19,989	(58)%
Income tax benefit	(1,206)	(448)	(758)	169 %
Net loss	$ (13,456)	$ (34,203)	$ 20,747	(61)%
Expenses per boe:[1]				
Lease operating expenses	$ 28.30	$ 21.92	$ 6.38	29 %
Electricity generation expenses	2.21	2.51	(0.30)	(12)%
Electricity sales[1]	(2.68)	(3.45)	0.77	(22)%
Transportation expenses	0.47	0.68	(0.21)	(31)%
Transportation sales[1]	(0.03)	(0.05)	0.02	(40)%
Marketing expenses	0.06	0.46	(0.40)	(87)%
Marketing revenues[1]	(0.06)	(0.48)	0.42	(88)%
Derivatives settlements received for gas purchases[1]	(2.47)	(5.72)	3.25	(57)%
Total operating expenses	$ 25.80	$ 15.87	$ 9.93	63 %
Total unhedged operating expenses[2]	$ 28.27	$ 21.59	$ 6.68	31 %
Total non-energy operating expenses[3]	$ 14.83	$ 12.73	$ 2.10	16 %
Total energy operating expenses[4]	$ 10.97	$ 3.14	$ 7.83	249 %
General and administrative expenses[5]	$ 9.63	$ 6.74	$ 2.89	43 %
Depreciation, depletion and amortization	$ 16.25	$ 14.17	$ 2.08	15 %
Taxes, other than income taxes	$ 3.72	$ 4.30	$ (0.58)	(13)%

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

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

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

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

(5) Includes non-recurring costs and non-cash stock compensation expense, in aggregate, of approximately $1.66 per boe and $1.31 per boe for the six months ended June 30, 2022 and June 30, 2021, respectively.

Expenses and Other

On a hedged basis, operating expenses increased 63%, or $9.93 per boe, to $25.80 for the six months ended June 30, 2022 from $15.87 per boe for the six months ended June 30, 2021. This increase was due to higher energy operating expense of $7.83 per boe and non-energy operating expense of $2.10 per boe. Energy operating expense increased primarily due to higher hedged purchased natural gas costs. Non-energy operating expense increased largely due to our focus on expense workovers to optimize our base production in the six months ended June 30, 2022 compared to same period of 2021. Additionally, inflation impacted non-energy costs.

Unhedged lease operating expenses were $28.30 per boe for the six months ended June 30, 2022, a 29% or $6.38 per boe increase compared to $21.92 for the six months ended June 30, 2021, driven by $3.83 per boe higher unhedged fuel costs for our California steam operations. Unhedged average fuel purchase price per mmbtu increased 34% in the six months ended June 30, 2022 compared to the six months ended June 30, 2021. Non-fuel lease operating expense increased $2.55 per boe in the six months ended June 30, 2022 when compared the same period of 2021. Key increases included higher workover and field monitoring activity associated with our field optimization program, and well and surface facilities maintenance. A portion of these higher costs were driven by inflation.

Cost of services in 2022 consisted entirely of costs from the well servicing and abandonment business we acquired on October 1, 2021, thus no prior period costs.

Electricity generation expenses decreased approximately 12% to $2.21 per boe for the six months ended June 30, 2022 from $2.51 per boe for the same period in 2021 due to lower volumes sold, resulting from the previously discussed sale of a cogeneration facility. 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, 2022 and June 30, 2021 consisted of gains of $18 million and $39 million, respectively. The settlement gain for the six months ended June 30, 2022 was $12 million, or $2.47 per boe, compared to a gain of $28 million, or $5.72 per boe, for same period in 2021, driven by a narrower spread between index gas prices and settled derivative fixed prices in 2022 compared to that of 2021. The mark-to-market valuation gain for the six months ended June 30, 2022 was $7 million compared to $11 million for the same period in 2021, consistent with the changes in future prices at the end of each period. Because we are the fixed price payer on these natural gas swaps, generally, increases in the associated price index above the swap fixed price creates valuation gains.

Transportation expenses declined primarily due to the divestiture of our Piceance properties in early 2022.

Marketing expenses were not material for the six months ended June 30, 2022 and June 30, 2021.

General and administrative expenses increased $13 million, or 39%, to approximately $46 million for the six months ended June 30, 2022 compared to the six months ended June 30, 2021. The majority of the increase was from the acquisition of CJWS in October of 2021; therefore, the comparable period of last year had no such expenses. For the six months ended June 30, 2022 and June 30, 2021, general and administrative expenses included non-cash stock compensation costs of approximately $8 million and $6 million, respectively. We incurred approximately $0.2 million related to the CJWS acquisition which have been categorized as non-recurring for the six months ended June 30, 2022. There were no non-recurring expenses in the same period of 2021.

Adjusted general and administrative expenses, which exclude non-cash stock compensation costs and non-recurring costs, increased $11 million, or 42%, to $38 million for the six months ended June 30, 2022 compared to $27 million for the six months ended June 30, 2021. The year-over-year increase was primarily due to the CJWS acquisition and employee cost inflation to remain competitive.

DD&A increased $8 million, or 12%, to approximately $78 million for the six months ended June 30, 2022 compared to the six months ended June 30, 2021. The CJWS acquisition increased depreciation by $6 million with the balance of the increase from slightly higher depletion rates in the D&P segment.

Taxes, Other Than Income Taxes

	Six Months Ended June 30,			
	2022	2021	$ Change	% Change
	(per boe)			
Severance taxes	$ 1.40	$ 0.98	$ 0.42	43 %
Ad valorem and property taxes	1.50	2.00	(0.50)	(25)%
Greenhouse gas allowances	0.82	1.32	(0.50)	(38)%
Total taxes other than income taxes	$ 3.72	$ 4.30	$ (0.58)	(13)%

Taxes, other than income taxes decreased 13% to $3.72 per boe for the six months ended June 30, 2022 compared to $4.30 per boe for the six months ended June 30, 2021. Severance taxes increased due to higher production and prices in Utah, while property taxes were lower due to the divestitures of Piceance and Placerita. GHG expense decreased due to lower emissions from the divestiture of Placerita and its cogeneration facility and allowances we acquired at relatively lower prices, more than offsetting higher mark-to-market valuations at June 30, 2022.

Other Operating Expenses (Income)

For the six months ended June 30, 2022 and 2021, other operating expenses were $4 million and $1 million, respectively. For the six months ended June 30, 2022, other operating expenses included $2 million of royalty audit charges incurred prior to our emergence and restructuring in 2017, and over $1 million loss on the divestiture of the Piceance properties. For the six months ended June 30, 2021, other operating expenses were net expenses of $1 million and primarily consisted of approximately $3 million of supplemental property tax assessments, royalty audit charges and tank rental costs, partially offset by $2 million of employee retention credits.

Interest Expense

Interest expense decreased 8% in the six months ended June 30, 2022 compared to the same period in 2021 as we had lower intra-period working capital borrowings on the 2021 RBL Facility in 2022.

Income Taxes

Our effective tax rate was 8% and 1% for the six months ended June 30, 2022 and June 30, 2021, respectively. The rates were impacted by changes in the valuation allowance recorded against deferred tax assets.

Non-GAAP Financial Measures

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

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

We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and unusual and infrequent items.

Our management believes Adjusted EBITDA provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and the investment community. The measure also allows our management to more effectively evaluate our operating performance and compare the results between periods without regard to our financing methods or capital structure. We also use Adjusted EBITDA in planning our capital allocation to sustain production levels and to determine our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility.

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

We define Discretionary Free Cash Flow as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. We expect to allocate 60% of Discretionary Free Cash Flow predominantly in the form of cash variable dividends, as well as opportunistic debt repurchases. The remaining 40% will be used for opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention. Our management believes Discretionary Free Cash Flow provides useful information in assessing our financial condition, and is the primary metric to determine the quarterly variable dividend.

While Adjusted EBITDA, Adjusted Net Income (Loss), Adjusted General and Administrative Expenses and Discretionary Free Cash Flow are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Net Income (Loss), Adjusted General and Administrative Expenses and Discretionary Free Cash Flow were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP 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 Net Income (Loss), Adjusted General and Administrative Expenses and Discretionary Free Cash Flow may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Net Income (Loss), Adjusted General and Administrative Expenses and Discretionary Free Cash Flow should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

Adjusted General and Administrative Expenses is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-cash stock compensation expense and unusual and infrequent costs. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period.

We exclude the items listed above from general and administrative expenses in arriving at Adjusted General and Administrative Expenses because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature.

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

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	June 30, 2022	June 30, 2021
	(in thousands)				
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$ 43,354	$ (56,810)	$ (12,881)	$ (13,456)	$ (34,203)
Add (Subtract):					
Interest expense	7,729	7,675	8,217	15,404	16,702
Income tax expense (benefit)	2,145	(3,351)	(72)	(1,206)	(448)
Depreciation, depletion and amortization	38,055	39,777	35,850	77,832	69,690
Losses on derivatives	51,319	132,804	44,014	184,123	69,788
Net cash paid for scheduled derivative settlements	(37,628)	(32,152)	(37,431)	(69,780)	(36,581)
Other operating expenses	353	3,769	42	4,122	841
Stock compensation expense	4,420	3,802	2,860	8,222	6,639
Non-recurring costs	—	198	—	198	—
Adjusted EBITDA	$ 109,747	$ 95,712	$ 40,599	$ 205,459	$ 92,428

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	June 30, 2022	June 30, 2021
			(in thousands)		
Adjusted EBITDA reconciliation to net cash provided by operating activities:					
Net cash provided by operating activities	$ 111,242	$ 48,530	$ 21,429	$ 159,772	$ 59,859
Add (Subtract):					
Cash interest payments	449	14,539	288	14,988	14,925
Cash income tax payments	2,484	—	—	2,484	—
Non-recurring costs	—	198	—	198	—
Other changes in operating assets and liabilities	(4,428)	32,445	18,882	28,017	17,644
Adjusted EBITDA	$ 109,747	$ 95,712	$ 40,599	$ 205,459	$ 92,428

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

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	June 30, 2022	June 30, 2021
			(in thousands)		
Adjusted Net Income (Loss) reconciliation to net income (loss):					
Net income (loss)	$ 43,354	$ (56,810)	$ (12,881)	$ (13,456)	$ (34,203)
Add (Subtract):					
Losses on derivatives	51,319	132,804	44,014	184,123	69,788
Net cash paid for scheduled derivative settlements	(37,628)	(32,152)	(37,431)	(69,780)	(36,581)
Other operating expenses	353	3,769	42	4,122	841
Non-recurring costs	—	198	—	198	—
Total additions, net	14,044	104,619	6,625	118,663	34,048
Income tax expense of adjustments and discrete income tax items	(4,262)	(4,938)	(37)	(9,200)	(511)
Adjusted Net Income (Loss)	$ 53,136	$ 42,871	$ (6,293)	$ 96,007	$ (666)
Basic EPS on Adjusted Net Income (Loss)	$ 0.67	$ 0.53	$ (0.08)	$ 1.20	$ (0.01)
Diluted EPS on Adjusted Net Income (Loss)	$ 0.64	$ 0.51	$ (0.08)	$ 1.15	$ (0.01)
Weighted average shares of common stock outstanding - basic	79,596	80,298	80,471	79,945	80,294
Weighted average shares of common stock outstanding - diluted	83,015	84,447	80,471	83,476	80,294

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

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	June 30, 2022	June 30, 2021
			(in thousands)		
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:					
General and administrative expenses	$ 23,183	$ 22,942	$ 16,065	$ 46,125	$ 33,135
Subtract:					
Non-cash stock compensation expense (G&A portion)	(4,263)	(3,706)	(2,763)	(7,969)	(6,432)
Non-recurring costs	—	(198)	—	(198)	—
Adjusted general and administrative expenses	$ 18,920	$ 19,038	$ 13,302	$ 37,958	$ 26,703
Development and production segment, and corporate	$ 15,635	$ 15,968	$ 13,302	$ 31,603	$ 26,703
Development and production segment, and corporate per $/boe	$ 6.55	$ 6.64	$ 5.35	$ 6.60	$ 5.43
Well servicing and abandonment segment	$ 3,285	$ 3,070	$ —	$ 6,355	$ —

The following table presents a reconciliation of the non-GAAP financial measure Discretionary Free Cash Flow to the GAAP financial measure of operating cash flow for each of the periods indicated.

	Three Months Ended		Six Months Ended
	June 30, 2022	March 31, 2022	June 30, 2022
		(in thousands)	
Discretionary Free Cash Flow:			
Operating cash flow(1)	$ 111,242	$ 48,530	$ 159,772
Subtract:			
Maintenance capital(2)(3)	(32,134)	(26,437)	(58,571)
Fixed dividends(4)	(4,726)	(5,236)	(9,962)
Discretionary Free Cash Flow	$ 74,382	$ 16,857	$ 91,239

(1) On a consolidated basis.

(2) D&P business only.

(3) Maintenance capital is the capital required to keep annual production flat, calculated as the capital expenditures for the D&P business during the period presented.

(4) Represents fixed dividends declared which are included in the “Dividends declared on common stock” line in the the consolidated statement of stockholders’ equity.

Liquidity and Capital Resources

Currently, we expect to fund our 2022 capital expenditures with cash flows from our operations. As of June 30, 2022, we had liquidity of $251 million, consisting of $58 million cash on hand and $193 million available for borrowings under our 2021 RBL Facility. We also have $400 million in aggregate principal amount 7% senior unsecured notes due February 2026 (the “2026 Notes”) outstanding as further discussed below.

Our shareholder return model, which went into effect January 1, 2022, is designed to increase cash returns to our shareholders, further demonstrating our commitment to be a leading returner of capital to our shareholders. The model is based on our Discretionary Free Cash Flow, which is defined as cash flow from operations less regular fixed dividends and the capital needed to hold production flat. See “Management’s Discussion and Analysis—Non-GAAP Financial Measures” for reconciliation of Discretionary Free Cash Flow to cash provided by operating activities, our most directly comparable financial measure calculated and presented in accordance with GAAP. Under this new model, the company intends to allocate Discretionary Free Cash Flow on a quarterly basis as follows: (a) 60% predominantly in the form of variable cash dividends to be paid quarterly, as well as opportunistic debt repurchases; (b) 40% in the form of discretionary capital, to be used for opportunistic growth, including from our extensive inventory of drilling opportunities, advancing our short- and long-term sustainability initiatives, share repurchases, and/or capital retention.

We currently believe that our liquidity, capital resources and cash on hand will be sufficient to conduct our business and operations for at least the next 12 months. 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 Discretionary Free Cash Flow we are currently generating and our liquidity and capital resources may not be sufficient to conduct our business and operations until commodity prices recover. Please see Part II, Item 1A “Risk Factors” for a discussion of known material risks, many of which are beyond our control, that could adversely impact our business, liquidity, financial condition, and results of operations.

2021 RBL Facility

On August 26, 2021, Berry Corp, as a guarantor, together with Berry LLC, as the borrower, entered into a credit agreement that provided for a revolving loan with up to $500 million of commitment, subject to a reserve borrowing base (as amended by the First Amendment, the Second Amendment and the Third Amendment, each as defined below, the “2021 RBL Facility”). Our initial borrowing base was $200 million. The 2021 RBL Facility provides a letter of credit subfacility for the issuance of letters of credit in an aggregate amount not to exceed $20 million. Issuances of letters of credit reduce the borrowing availability for revolving loans under the 2021 RBL Facility on a dollar for dollar basis. The 2021 RBL Facility matures on August 26, 2025, unless terminated earlier in accordance with the 2021 RBL Facility terms. Borrowing base redeterminations generally become effective each May and November, although the borrower and the lenders may each make one interim redetermination between scheduled redeterminations. In December 2021, we completed the first scheduled semi-annual borrowing base redetermination and entered into that certain First Amendment to Credit Agreement (the “First Amendment”), which resulted in a reaffirmed borrowing base at $200 million and changes to the hedging covenants in respect of the exclusion of short puts or similar derivatives in the calculation of minimum and maximum hedging requirements.

In May 2022, Berry Corp., as a guarantor, and Berry LLC, as the borrower, entered into that certain Second Amendment to Credit Agreement and Limited Consent and Waiver (the “Second Amendment”) pursuant to which, among other things, the requisite lenders under the 2021 RBL Facility (i) consented to certain dividends and distributions and to certain investments made by Berry LLC in C&J Well Services, LLC and/or CJ Berry Well Services Management, LLC, in each case, as further described therein, (ii) waived certain minimum hedging requirements for the time periods described therein, (iii) waived any breach, default or event of default which may have arisen as a result of any of the foregoing, (iv) amended the restricted payments covenant to give us additional flexibility to make restricted payments, subject to satisfaction of certain leverage and availability conditions and other conditions described below and in the Second Amendment and (v) amended the minimum hedging covenant to not, until October 1, 2022, require hedges for any full calendar month from and after January 1, 2025, as further described in the Second Amendment. In May 2022, we also completed our semi-annual borrowing base redetermination and entered into the Third Amendment to the Credit Agreement (the “Third Amendment”), which among other things (1) increased the borrowing base from 200,000,000 to $250,000,000; (2) established the Aggregate Elected Commitment Amounts (as defined in the 2021 RBL Facility) at $200,000,000 initially; and (3) converted all outstanding Eurodollar Loans (into Term Benchmark Loans (each as defined in the 2021 RBL Facility) with an initial interest period of one-month's duration and otherwise give effect to the transition from the London interbank offered rate ("LIBOR") to the secured overnight financing rate ("SOFR") by replacing the adjusted LIBOR rate with the term SOFR rate for one, three or six months plus 0.10% (subject to a floor of 0.50%).

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

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

The 2021 RBL Facility requires us to maintain on a consolidated basis as of each quarter-end (i) a leverage ratio of not more than 3.0 to 1.0 and (ii) a current ratio of not less than 1.0 to 1.0. As of June 30, 2022, our leverage ratio and current ratio were 1.3:1.0 and 2.5:1.0, respectively. In addition, the 2021 RBL Facility currently provides that, to the extent we incur unsecured indebtedness, including any amounts raised in the future, the borrowing base will be reduced by an amount equal to 25% of the amount of such unsecured debt. We were in compliance with all financial covenants under the 2021 RBL Facility as of June 30, 2022.

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

From and after August 26, 2022, the 2021 RBL Facility permits us to repurchase certain indebtedness so long as both before and after giving pro forma effect to such repurchase, no default or event of default exists, availability is equal to or greater than 20% of the borrowing base and our pro forma leverage ratio is less than or equal to 2.0 to 1.0. The 2021 RBL Facility also permits us to make restricted payments so long as both before and after giving pro forma effect to such distribution, no default or event of default exists, availability exceeds 75% of the borrowing base, and our pro forma leverage ratio is less than or equal to 1.5 to 1.0. In addition, we can make other restricted payments in an aggregate amount not to exceed 100% of Free Cash Flow (as defined under the 2021 RBL Facility) for the fiscal quarter most recently ended prior to such distribution so long as, in addition to other conditions and limitations as described in the 2021 RBL Facility, both before and after giving pro forma effect to such distribution, no default or event of default exists, availability is greater than 20% of the borrowing base and our pro forma leverage ratio is less than or equal to 2.0 to 1.0.

Berry LLC is the borrower on the 2021 RBL Facility and Berry Corp. is the guarantor. Each future subsidiary of

Berry Corp., with certain exceptions, is required to guarantee our obligations and obligations of the other guarantors under the 2021 RBL Facility and under certain hedging transactions and banking services arrangements (the “Guaranteed Obligations”). The lenders under the 2021 RBL Facility hold a mortgage on at least 90% of the present value of our proven oil and gas reserves. The obligations of Berry LLC and the guarantors are also secured by liens on substantially all of our personal property, subject to customary exceptions.

As of June 30, 2022, we had no borrowings outstanding, $7 million in letters of credit outstanding and approximately $193 million of available borrowing capacity under the 2021 RBL Facility.

Hedging

We have protected a significant portion of our anticipated cash flows in 2022 through 2024, using 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 natural gas purchases to protect against price increases. In addition, we also hedge to meet the hedging requirements of the 2021 RBL Facility. Our generally low-decline production base, coupled with our stable operating cost environment, affords an ability to hedge a material amount of our future expected production. We expect our operations to generate sufficient cash flows at current commodity prices including our current hedging positions. For information regarding risks related to our hedging program, see “Item 1A. Risk Factors—Risks Related to Our Operations and Industry” in our Annual Report.

As of June 30, 2022, we had the following hedges for our crude oil production and gas purchases.

	Q3 2022	Q4 2022	FY 2023	FY 2024	FY 2025
Brent					
Swaps					
Hedged volume (bbls)	1,380,000	1,288,000	3,433,528	1,917,000	—
Weighted-average price ($/bbl)	$ 77.73	$ 76.07	$ 73.06	$ 75.52	$ —
Put Spreads					
Hedged volume (bbls)	368,000	368,000	2,190,000	1,281,000	—
Weighted-average price ($/bbl)	$50.00/$40.00	$50.00/$40.00	$50.00/$40.00	$50.00/$40.00	$ —
Producer Collars					
Hedged volume (bbls)	—	—	1,460,000	1,098,000	—
Weighted-average price ($/bbl)	$ —	$ —	$40.00/$106.00	$40.00/$105.00	$ —
Henry Hub - Natural Gas purchases					
Consumer Collars					
Hedged volume (mmbtu)	3,680,000	3,680,000	5,430,000	—	—
Weighted-average price ($/mmbtu)	$4.00/$2.75	$4.00/$2.75	$4.00/$2.75	$ —	$ —
NWPL - Natural Gas purchases					
Swaps					
Hedged volume (mmbtu)	—	1,220,000	12,800,000	7,320,000	6,080,000
Weighted-average price ($/mmbtu)	$ —	$ 6.40	$ 5.48	$ 4.27	$ 4.27

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

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	June 30, 2022	June 30, 2021
Crude Oil (per bbl):					
Realized sales price, before the effects of derivative settlements	$ 105.70	$ 92.25	$ 64.72	$ 98.95	$ 60.83
Effects of derivative settlements	$ (21.92)	$ (15.38)	$ (18.33)	$ (18.64)	$ (15.22)
Oil with hedges ($/bbl)	$ 83.78	$ 76.87	$ 46.39	$ 80.31	$ 45.61
Purchased Natural Gas (per mmbtu):					
Purchase price, before the effects of derivative settlements	$ 7.30	$ 6.30	$ 3.31	$ 6.80	$ 5.08
Effects of derivative settlements	$ (1.89)	$ (0.29)	$ (0.31)	$ (1.08)	$ (2.36)
Purchased Natural Gas with hedges	$ 5.41	$ 6.01	$ 3.00	$ 5.72	$ 2.72

Cash Dividends

Our Board of Directors approved regular fixed cash dividends of $0.06 per share on our common stock for each of the first two quarters of 2022, which were paid in April and July 2022. The Board of Directors approved a $0.13 per share variable dividend on our common stock based on our first quarter results, which was paid in June 2022. In July 2022, the Board of Directors approved a $0.06 per share regular fixed cash dividend on our common stock and a variable dividend of 0.56 on our common stock based on the second quarter results. Both dividends approved in July 2022 are expected to be paid at the same time in August 2022. As of July 31, 2022, the Company has declared approximately $151 million in fixed and variable dividends since the inception of our dividend program in the third quarter of 2018. When combined with the $75 million in stock repurchases to date, this represents a 205% return of capital on our IPO net proceeds.

Stock Repurchase Program

The Company repurchased 2 million shares during the three months ended June 30, 2022 for approximately $23 million. As of June 30, 2022, the Company had repurchased a total of 7,528,704 shares under the stock repurchase program for approximately $75 million in aggregate. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company intends to allocate a portion of Discretionary Free Cash Flow to opportunistic share repurchases.

In April 2022, our Board of Directors approved an increase of $102 million to the Company’s stock repurchase authorization bringing the Company’s total share repurchase authority to $150 million. As of June 30, 2022, the Company’s remaining total share repurchase authority is $127 million, after the repurchases made in the second quarter of 2022. The Board’s authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions, subject to market conditions and other factors, up to the aggregate amount authorized by the Board. The Board’s authorization has no expiration date.

Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and 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.

Debt Repurchase Program

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

Statements of Cash Flows

The following is a comparative cash flow summary:

	Six Months Ended June 30,	
	2022	2021
	(in thousands)	
Net cash:		
Provided by operating activities	$ 159,772	$ 59,859
Used in investing activities	(75,423)	(60,512)
Used in financing activities	(47,137)	(4,986)
Net increase (decrease) in cash and cash equivalents	$ 37,212	$ (5,639)

Operating Activities

Cash provided by operating activities increased for the six months ended June 30, 2022 by approximately $100 million when compared to the six months ended June 30, 2021, and the most significant increases were sales of $167 million and an increase of $9 million related to the net margin for CJWS, partially offset by an increase of $33 million in derivative settlements paid, an increase of $5 million in general and administrative expenses, an increase of $17 million in unhedged operating expenses, an increase in other operating expenses of $3 million and a decrease of $18 million in working capital and other changes.

Investing Activities

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

	Six Months Ended June 30,	
	2022	2021
	(in thousands)	
Capital expenditures:		
Capital expenditures	$ (61,706)	$ (67,030)
Changes in capital expenditures accruals	5,363	6,934
Acquisitions, net of cash received	(19,080)	(825)
Proceeds from sale of properties and equipment and other	—	409
Cash used in investing activities	$ (75,423)	$ (60,512)

Cash used in investing activities increased $15 million for the six months ended June 30, 2022 when compared to the same period in 2021, primarily due to an increase in cash used for acquisitions, partially offset by lower cash used for capital expenditures.

Financing Activities

Cash used by financing activities in 2022 was primarily for the purchase of treasury stock of $23 million, for dividends paid of $20 million and for taxes on equity awards of $4 million. In 2021, the cash used was primarily for dividends paid on common stock of $3 million and for taxes on equity awards of $2 million.

Guarantor Financial Information

The 2026 Notes and 2021 RBL Facility were issued by Berry LLC ("Issuer") and are guaranteed by Berry Corp ("Parent Guarantor"). See Note 3—Debt in the 2021 Annual Report for further information. The Issuer is 100% owned by the Parent Guarantor. The Parent Guarantor has no independent assets or operations and is subject to a passive holding company covenant under the 2021 RBL Facility. Any guarantees of potential future registered debt securities by Berry Corp. or Berry LLC would be full and unconditional. In addition, there are no significant restrictions upon the ability of Berry LLC to distribute funds to Berry Corp. by distribution or loan other than restrictions under the 2021 RBL Facility. None of the assets of Berry Corp. or Berry LLC represent restricted net assets.

For cash management purposes, the Company transfers cash between the Parent Guarantor, Issuer and non-guarantors through intercompany receivables and payables. While the non-guarantor subsidiaries do not guarantee the Issuer's obligations under our outstanding debt, the transfer of cash under these activities facilitates the ability of the recipient to make specified third-party payments for principal and interest on the 2026 Notes and 2021 RBL Facility.

The summarized financial information of the Guarantor and Issuer is presented below on a combined basis after the elimination of: (i) intercompany transactions among such entities and (ii) equity in earnings from and investments in the non-guarantor subsidiaries. Transactions with, and amounts due to or from, non-guarantor subsidiaries are separately disclosed.

	Six Months Ended June 30, 2022	
	(in thousands) (unaudited)	
Total revenue to third parties	$	463,715
Total expenses	$	281,817
Net loss	$	(16,478)

	June 30, 2022		As of December 31, 2021	
	(in thousands) (unaudited)			
Receivables from non-guarantor subsidiaries	$	556	$	16,792
Other current assets		173,902		114,983
Total current assets	$	174,458	$	131,775
Noncurrent assets	$	1,338,064	$	1,317,241
Other current liabilities	$	247,131	$	179,691
Other noncurrent liabilities	$	627,646	$	576,681

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2021 to June 30, 2022 are discussed below.

	June 30, 2022	December 31, 2021
	(in thousands)	
Cash and cash equivalents	$ 52,495	$ 15,283
Accounts receivable, net	$ 117,281	$ 86,269
Derivative instruments assets - current and long-term	$ —	$ 1,070
Other current assets	$ 35,122	$ 45,946
Property, plant & equipment, net	$ 1,313,927	$ 1,301,349
Other noncurrent assets	$ 11,560	$ 6,562
Accounts payable and accrued expenses	$ 160,683	$ 157,524
Derivative instruments liabilities - current and long-term	$ 160,667	$ 48,202
Long-term debt	$ 395,135	$ 394,566
Deferred income taxes liability - long-term	$ 1,322	$ 1,831
Asset retirement obligations - long-term	$ 139,956	$ 143,926
Other noncurrent liabilities	$ 31,853	$ 17,782
Stockholders' equity	$ 640,769	$ 692,648

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

The $31 million increase in accounts receivable was driven by $24 million higher sales period-over-period, primarily due to higher crude prices. Another $7 million of the increase is attributable to higher sales from the well servicing and abandonment segment.

The $11 million decrease in other current assets is primarily due to a $3 million refund of prepaid permitting fees, a $3 million refund of letter of credit collateral, $2 million for adjustments related to transition services provided for recent divestitures, $2 million for the expensing of prepaid expenses, mostly insurance, for the well servicing and abandonment segment, as well as $1 million for inventory moved to capital projects.

The $13 million increase in property, plant and equipment was primarily due to $66 million in capital investments and $19 million of acquisitions, primarily the Antelope Creek oil and gas properties in Utah, offset by year to date depreciation of $72 million.

The $5 million increase in other noncurrent assets was primarily due to the adoption of new lease accounting rules in the first quarter for $7 million, net of accumulated amortization, partially offset by amortization of debt issuance costs of $1 million and $1 million for the well servicing and abandonment segment.

The $3 million increase in accounts payable and accrued expenses included $7 million in the well servicing and abandonment segment payables, $4 million in other accrued expenses, $2 million in higher monthly royalties payable due to higher prices, $1 million for the current portion of lease liability, partially offset by decreases of $8 million in greenhouse gas emissions obligation, and $3 million in trade payables.

The $114 million increase in net derivative liabilities is due to the change from a net liability of $47 million at December 31, 2021 to a net liability of $161 million as of June 30, 2022. 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 $4 million decrease in the long-term portion of the asset retirements obligations from $144 million at December 31, 2021 to $140 million at June 30, 2022 was due to $11 million of liabilities settled during the period and $1 million reduction due to property sales offset by $5 million of accretion expense and $3 million of liabilities incurred.

The 14 million increase in other noncurrent liabilities was due to $8 million of non-current greenhouse gas liabilities incurred, and $6 million for the long term portion of lease liability based on the adoption of new lease accounting rules in the first quarter.

The $52 million decrease in stockholders' equity was due to the net loss of $13 million, $20 million of common stock dividends declared, $23 million for the purchase of treasury stock and $4 million of shares withheld for payment of taxes on equity awards. These decreases were partially offset by $8 million of stock-based equity awards, net of taxes.

Lawsuits, Claims, Commitments, and Contingencies

In the normal course of business, we, or our subsidiaries, are the subject of, or party to, pending or threatened legal proceedings, contingencies and commitments involving a variety of matters that seek, or may seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, fines and penalties, remediation costs, or injunctive or declaratory relief.

We accrue for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. We have not recorded any reserve balances at June 30, 2022 and December 31, 2021. 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, 2022, we are not aware of material indemnity claims pending or threatened against us.

Securities Litigation Matter

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the "Torres Lawsuit") in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (collectively, the "Defendants"). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act, on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company's 2018 IPO; or (ii) Berry Corp.'s securities between July 26, 2018 and November 3, 2020 (the "Class Period"). In particular, the complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company's business, operational efficiency and stability, and compliance policies, that artificially inflated the Company's stock price, resulting in injury to the purported class members when the value of Berry Corp.'s common stock declined following release of its financial results for the third quarter of 2020 on November 3, 2020.

On January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Exchange Act, alleging, among other things, that the Company and the individual Defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company's permits and permitting processes. The amended complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys' fees and costs. The Defendants filed a Motion to Dismiss on January 24, 2022, for which the Court's ruling is pending.

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

Contractual Obligations

The following is a summary of our commitments and contractual obligations as of June 30, 2022:

	Payments Due				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Off-Balance Sheet arrangements:					
Processing and transportation contracts[1]	$ 93,431	$ 10,754	$ 18,252	$ 16,165	$ 48,260
Other purchase obligations[2]	17,100	6,600	10,500	—	—
Total contractual obligations	$ 110,531	$ 17,354	$ 28,752	$ 16,165	$ 48,260

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

(2) Amounts include a drilling commitment in California, for which we are required to drill 57 wells with an estimated total cost and minimum commitment of $17.1 million by October 2023. In May 2022, the drilling commitment was extended to October 2023, which moved approximately $8 million from a short-term commitment to a long-term commitment. Per the new agreement, 22 wells estimated at $6.6 million are required to be drilled within one year.

Critical Accounting Policies and Estimates

See Note 1, Basis of Presentation, in the Notes to Consolidated Condensed Financial Statements in Part I, Item 1 of this Form 10-Q and Part II, Item 7 “Critical Accounting Policies and Estimates” in the 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 of 1933 and Section 21E of the Securities Exchange Act of 1934. 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, Discretionary Free Cash Flow), financial and operating results, capital program and development and production plans, operations and business strategy, potential acquisition and other strategic opportunities, reserves, hedging activities, capital expenditures, return of capital, our shareholder return model and the payment of future dividends, future repurchases of stock or debt, capital investments, our ESG strategy and the initiation of new projects or business in connection therewith, recovery factors, and other guidance, are forward-looking statements. These statements are based upon various assumptions, many of which are based, in turn, upon further assumptions. Although we believe that these assumptions were reasonable when made, these assumptions are inherently subject to significant uncertainties and contingencies which are difficult or impossible to predict and are beyond our control. Therefore, such forward-looking statements involve significant risks and uncertainties that could materially affect our expected financial position, financial and operating results, liquidity, cash flows (including, but not limited to, Discretionary Free Cash Flow), and business prospects. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect us are discussed below in Part II, Item 1A. “Risk Factors” in this Quarterly Report, as well as in Part I, Item 1A. “Risk Factors” our most recent Annual Report and other filings with the Securities and Exchange Commission.

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

- the regulatory environment, including availability or timing of, and conditions imposed on, obtaining and/or maintaining permits and approvals, including those necessary for drilling and/or development projects;
- the impact of current, pending and/or future laws and regulations, and of legislative and regulatory changes and other government activities, including those related to permitting, drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- inflation levels, particularly the recent rise to historically high levels, and government efforts to reduce inflation, including increased interest rates;
- the length, scope and severity of the ongoing COVID-19 pandemic or the emergence of a new pandemic, including the effects of related public health concerns and the impact of actions taken by governmental authorities and other third parties in response to the pandemic and its impact on commodity prices, supply and demand considerations, global supply chain disruptions and labor constraints;
- global economic trends, geopolitical risks and general economic and industry conditions, such as the economic impact from the COVID-19 pandemic, including the global supply chain disruptions and the government interventions into the financial markets and economy, among other factors;
- overall domestic and global political and economic conditions, including 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, or a prolonged recession;
- those resulting from the COVID-19 pandemic;
- the actions of foreign producers, importantly including OPEC+ and changes in OPEC+'s production levels;
- volatility of oil, natural gas and NGL prices, including as a result of political instability, armed conflict or economic sanctions;
- the California and global energy future, including the factors and trends that are expected to shape it, such as concerns about climate change and other air quality issues, the transition to a low-emission economy and the expected role of different energy sources;
- supply of and demand for oil, natural gas and NGLs, including due to the actions of foreign producers, importantly including OPEC+ and change in OPEC+'s production levels;
- disruptions to, capacity constraints in, or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures, meet our working capital requirements or fund planned investments;
- price fluctuations and availability of natural gas and electricity and the cost of steam;
- our ability to use derivative instruments to manage commodity price risk;
- our ability to meet our planned drilling schedule, including due to our ability to obtain permits on a timely basis or at all, and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- concerns about climate change and other air quality issues;

- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- drilling and production results, lower–than–expected production, reserves or resources from development projects or higher–than–expected decline rates;
- our ability to obtain timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells;
- changes in tax laws;
- effects of competition;
- uncertainties and liabilities associated with acquired and divested assets;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- market fluctuations in electricity prices and the cost of steam;
- asset impairments from commodity price declines;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- geographical concentration of our operations;
- the creditworthiness and performance of our counterparties with respect to our hedges;
- impact of derivatives legislation affecting our ability to hedge;
- failure of risk management and ineffectiveness of internal controls;
- catastrophic events, including wildfires, earthquakes and pandemics;
- environmental risks and liabilities under federal, state, tribal and local laws and regulations (including remedial actions);
- potential liability resulting from pending or future litigation;
- our ability to recruit and/or retain key members of our senior management and key technical employees;
- information technology failures or cyberattacks; and.
- governmental actions and political conditions, as well as the 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 to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise except as required by applicable law.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As of June 30, 2022, there have been no material changes in the information required to be provided under Item 305 of Regulation S-K included under the caption *Management's Discussion and Analysis of Financial Condition and Results of Operations (Incorporating Item 7A)- Quantitative and Qualitative Disclosures About Market Risk,* in the 2021 Annual Report, except as discussed below.

Price Risk

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

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

We determine the fair value of our oil and gas sales and natural gas purchase derivatives using valuation techniques which utilize market quotes and pricing analysis. Inputs include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. We validate data provided by third parties by understanding the valuation inputs used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. At June 30, 2022, the fair value of our hedge positions was a net liability of approximately $161 million. A 10% increase in the oil and natural gas index prices above the June 30, 2022 prices would result in a net liability of approximately $222 million; conversely, a 10% decrease in the oil and natural gas index prices below the June 30, 2022 prices would result in a net liability of approximately $86 million. For additional information about derivative activity, see Note 3, Derivatives, in the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 of this report.

Actual gains or losses recognized related to our derivative contracts depend exclusively on the price of the underlying commodities on the specified settlement dates provided by the derivative contracts. Additionally, we cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our cash flows could be negatively impacted.

Item 4. Controls and Procedures

Our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer supervised and participated in our evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, they each concluded that our disclosure controls and procedures were effective as of June 30, 2022.

There were no changes in the Company's internal control over financial reporting during the second quarter of 2022 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II – Other Information

Item 1. Legal Proceedings

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

Securities Litigation Matter

On November 20, 2020, Luis Torres, individually and on behalf of a putative class, filed a securities class action lawsuit (the “Torres Lawsuit”) in the United States District Court for the Northern District of Texas against Berry Corp. and certain of its current and former directors and officers (collectively, the “Defendants”). The complaint asserts violations of Sections 11 and 15 of the Securities Act of 1933, and Sections 10(b) and 20(a) of the Exchange Act, on behalf of a putative class of all persons who purchased or otherwise acquired (i) common stock pursuant and/or traceable to the Company’s 2018 IPO; or (ii) Berry Corp.'s securities between July 26, 2018 and November 3, 2020 (the “Class Period”). In particular, the complaint alleges that the Defendants made false and misleading statements during the Class Period and in the offering materials for the IPO, concerning the Company’s business, operational efficiency and stability, and compliance policies, that artificially inflated the Company’s stock price, resulting in injury to the purported class members when the value of Berry Corp.’s common stock declined following release of its financial results for the third quarter of 2020 on November 3, 2020.

On January 21, 2021, multiple plaintiffs filed motions in the Torres Lawsuit seeking to be appointed lead plaintiff and lead counsel. After briefing and a stipulation between the remaining movants, the Court appointed Luis Torres and Allia DeAngelis as co-lead plaintiffs on August 18, 2021. On November 1, 2021, the co-lead plaintiffs filed an amended complaint asserting claims on behalf of the same putative class under Sections 11 and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Exchange Act, alleging, among other things, that the Company and the individual Defendants made false and misleading statements between July 26, 2018 and November 3, 2020 regarding the Company’s permits and permitting processes. The amended complaint does not quantify the alleged losses but seeks to recover all damages sustained by the putative class as a result of these alleged securities violations, as well as attorneys’ fees and costs. The Defendants filed a Motion to Dismiss on January 24, 2022, for which the Court’s ruling is pending.

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

Other Matters.

For additional information regarding legal proceedings, see Note 4 to the condensed consolidated financial statements in Part I of this Form 10-Q and Note 5 to our consolidated financial statements for the year ended December 31, 2021 included in the Annual Report.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. A discussion of such risks and uncertainties may be found under the heading “Item 1A. Risk Factors” in our most recent Annual Report.

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

Stock Repurchase Program

The Company repurchased 2 million shares during the three months ended June 30, 2022 for approximately $23 million. As of June 30, 2022, the Company had repurchased a total of 7,528,704 shares under the stock repurchase program for approximately $75 million in aggregate. As previously disclosed, the Company implemented a shareholder return model in early 2022, for which the Company intends to allocate a portion of Discretionary Free Cash Flow to opportunistic share repurchases.

In April 2022, our Board of Directors approved an increase of $102 million to the Company's stock repurchase authorization bringing the Company's total share repurchase authority to $150 million. As of June 30, 2022, the Company's remaining total share repurchase authority is $127 million, after the repurchases made in the second quarter of 2022. The Board's authorization permits the Company to make purchases of its common stock from time to time in the open market and in privately negotiated transactions, subject to market conditions and other factors, up to the aggregate amount authorized by the Board. The Board's authorization has no expiration date.

Repurchases may be made from time to time in the open market, in privately negotiated transactions or by other means, as determined in the Company's sole discretion. The manner, timing and amount of any purchases will be determined based on our evaluation of market conditions, stock price, compliance with outstanding agreements and other factors, may be commenced or suspended at any time without notice and 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.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
April 1 - 30, 2022	—	$ —	—	$ —
May 1 - 31, 2022	2,000,000	$ 11.38	2,000,000	$ 126,804,000
June 1 - 30, 2022	—	$ —	—	$ —
Total	2,000,000	$ —	2,000,000	$ 126,804,000

Item 6. Exhibits

Exhibit Number	Description
3.1	Second Amended and Restated Certificate of Incorporation of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.1 of Form 8-K filed February 19, 2020)
3.2	Third Amended and Restated Bylaws of Berry Corporation (bry) (incorporated by reference to Exhibit 3.2 of Form 8-K filed February 19, 2020)
3.3	Certificate of Designation of Series A Convertible Preferred Stock of Berry Petroleum Corporation (incorporated by reference to Exhibit 3.4 to the Company's Registration Statement on Form S-1 (File No. 333-226011))
3.4	Certificate of Amendment to Certificate of Designation (incorporated by reference to Exhibit 3.1 of Form 8-K filed July 30, 2018)
10.1	Second Amendment to Credit Agreement, dated May 2, 2022, by and among Berry Petroleum Company, LLC, as borrower, Berry Corporation (bry), as guarantor, JP Morgan Chase Bank, N.A., as administrative agent and the lenders parties thereto (incorporated by reference to Exhibit 10.6 of the Quarterly Report on Form 10-Q filed May 4, 2022)
10.2	Third Amendment to Credit Agreement dated May 27, 2022, by and among Berry Corporation (bry), as a guarantor, together with Berry Petroleum Company, LLC, as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and as an issuing bank, and the lenders from time-to-time party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed June 1, 2022)
31.1*	Section 302 Certification of Chief Executive Officer
31.2*	Section 302 Certification of Chief Financial Officer
32.1*	Section 906 Certification of Chief Executive Officer and Chief Financial Officer
101.INS*	Inline XBRL Instance Document (the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Data Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

(*) Filed herewith.

GLOSSARY OF COMMONLY USED TERMS

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

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

"*AROs*" means asset retirement obligations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*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, 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.

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

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

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

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

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

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

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

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

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

"*Discretionary Free Cash Flow*" is a non-GAAP financial measure defined as cash flow from operations less regular fixed dividends and the capital needed to hold production flat.

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

"D&P" means our development and production business segment, which is engaged in the development and production of onshore, low geologic risk, long-lived conventional oil reserves primarily located in California, as well as Utah.

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

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

"*EOR*" means enhanced oil recovery.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*ICE*" means Intercontinental Exchange.

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

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

"*IOR*" means improved oil recovery.

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

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

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

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

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

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

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

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

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

"*mm*bb*l*" means one million barrels of oil, condensate or NGLs.

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

"*mmbtu*" means one million btus.

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

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

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

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

"*MW*" means megawatt.

"*MWHs*"means megawatt hours.

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

"*NASDAQ*" means Nasdaq Global Select Market.

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

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

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

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

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

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

"*NYMEX*" means New York Mercantile Exchange.

"*Oil*" means crude oil or condensate.

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

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

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

"*OTC*" means over-the-counter

"*PALs*" is an abbreviation for project approval letters.

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

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

"*PDP*" is an abbreviation for proved developed producing.

"*Permeability*" means the ability, or measurement of a rock's ability, to transmit fluids.

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

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

"*PPA*" is an abbreviation for power purchase agreement.

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

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

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

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

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

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

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

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

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

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

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

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

"*QF*" means qualifying facility.

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

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

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

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

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

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

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

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

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

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

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

"SARs" is an abbreviation for stock appreciation rights.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Well servicing and abandonment" means the CJWS business segment.

"*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 3, 2022	*/s/* Cary Baetz
		Cary Baetz Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date:	August 3, 2022	*/s/* M. S. Helm
		Michael S. Helm Chief Accounting Officer (Principal Accounting Officer)

EXHIBIT 31.1

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

I, A. T. “Trem” Smith, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2022

/s/ A. T. Smith

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

EXHIBIT 31.2

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

I, Cary Baetz, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2022

/s/ Cary Baetz

Cary Baetz
Executive Vice President and
Chief Financial Officer

EXHIBIT 32.1

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

In connection with the quarterly report on Form 10-Q of Berry Corporation (bry) (the “Company”) for the fiscal period ended June 30, 2022, as filed with the Securities and Exchange Commission on August 3, 2022 (the “Report”), A. T. “Trem” Smith, as Chief Executive Officer of the Company, and Cary Baetz, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section § 1350, as adopted pursuant to Section § 906 of the Sarbanes-Oxley Act of 2002, to the best of our knowledge that:

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

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

Date: August 3, 2022

/s/ A. T. Smith
A. T. “Trem” Smith
President and Chief Executive Officer

Date: August 3, 2022

/s/ Cary Baetz
Cary Baetz
Executive Vice President and
Chief Financial Officer

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

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