UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(mark one)

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

For the quarterly period ended June 30, 2026

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: 000-56598

NORTHWESTERN ENERGY GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	**93-2020320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3010 W. 69th Street Sioux Falls South Dakota	**57108**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 605-978-2900

N/A

(Former name, former address and former fiscal year, if changed since last report)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock	NWE	Nasdaq Stock Market LLC

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common Stock, Par Value $0.01, 61,517,850 shares outstanding at July 24, 2026

NORTHWESTERN ENERGY GROUP

FORM 10-Q

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Quarterly Report on Form 10-Q regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Quarterly Report, relating to our current expectations of future financial performance, continued growth, changes in economic conditions or capital markets, changes in customer usage patterns and preferences, and statements relating to our pending merger with Black Hills Corporation are 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.

Words or phrases such as “anticipates," “may," “will," “should," “believes," “estimates," “expects," “intends," “plans," “predicts," “projects," “targets," “will likely result," “will continue" or similar expressions identify forward-looking statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. We caution that while we make such statements in good faith and believe such statements are based on reasonable assumptions, including without limitation, our examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- risks relating to the pending merger transaction pursuant to that certain Agreement and Plan of Merger dated August 18, 2025 (Merger Agreement) between NorthWestern and Black Hills Corporation (Black Hills), including, among others, (1) the risk of delays in consummating the pending merger transaction, including as a result of required regulatory approvals, which may not be obtained on the expected timeline, or at all, (2) the risk of any event, change or other circumstance that could give rise to the termination of the Merger Agreement, (3) the risk that required regulatory approvals are subject to conditions not anticipated by NorthWestern and Black Hills, (4) the possibility that the anticipated benefits and projected value creation of the pending merger transaction will not be realized or will not be realized within the expected time period, (5) disruption to the parties’ businesses as a result of the announcement and pendency of the merger transaction, including potential distraction of management from current plans and operations of NorthWestern or Black Hills and the ability of NorthWestern or Black Hills to retain and hire key personnel, (6) reputational risk and the reaction of each company’s customers, suppliers, employees or other business partners to the pending merger transaction, (7) the possibility that the pending merger transaction may be more expensive to complete than anticipated, including as a result of unexpected factors or events, (8) the outcome of any legal or regulatory proceedings that may be instituted against NorthWestern or Black Hills related to the Merger Agreement or the pending merger transaction, (9) the risks associated with third party contracts containing consent and/or other provisions that may be triggered by the pending merger transaction, (10) legislative, regulatory, political, market, economic and other conditions, developments and uncertainties affecting NorthWestern's or Black Hills' businesses; (11) the evolving legal, regulatory and tax regimes under which NorthWestern and Black Hills operate; (12) restrictions during the pendency of the merger transaction that may impact NorthWestern's or Black Hills' ability to pursue certain business opportunities or strategic transactions; and (13) unpredictability and severity of catastrophic events, including, but not limited to, extreme weather, natural disasters, acts of terrorism or outbreak of war or hostilities, as well as NorthWestern's and Black Hills' response to any of the aforementioned factors;
- adverse determinations by regulators, such as adverse outcomes from the denial of interim rates, final rates not consistent with a reasonable ability to earn our allowed returns, failure to timely approve our requests associated with recovering the operating costs for the additional interests in Colstrip Units 3 and 4, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, and wildfire damages in excess of liability insurance coverage, could have a material effect on our liquidity, results of operations and financial condition;
- our ability to attract and serve large new load customers, including data centers and other energy-intensive operations, depends on regulatory and legislative actions supportive of a framework for review and approval of these large new load customer contracts;
- our ability to enter agreements to sell excess capacity and associated energy from additional interests in Colstrip Units 3 and 4 on favorable commercial and economic terms;

- the impact of extraordinary external events and natural disasters, such as a wide-spread or global pandemic, geopolitical events, earthquake, flood, drought, lightning, weather, wind, and fire, could have a material effect on our liquidity, results of operations and financial condition;
- acts of terrorism, cybersecurity attacks, data security breaches, or other malicious acts that cause damage to our generation, transmission, or distribution facilities, information technology systems, or result in the release of confidential customer, employee, or Company information;
- supply chain constraints, tariffs on certain imported products, recent high levels of inflation for products, services and labor costs, and their impact on capital expenditures, operating activities, and/or our ability to safely and reliably serve our customers;
- changes in availability of trade credit, creditworthiness of counterparties, usage, commodity prices, fuel supply costs or availability due to higher demand, shortages, weather conditions, transportation problems or other developments, may reduce revenues or may increase operating costs, each of which could adversely affect our liquidity and results of operations;
- unscheduled generation outages or forced reductions in output, maintenance or repairs, which may reduce revenues and increase operating costs or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption "Risk Factors" which is part of the disclosure included in Part II, Item 1A of this Quarterly Report on Form 10-Q.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-K, 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls, and other communications released to the public. We believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable. However, any or all of the forward-looking statements in this Quarterly Report on Form 10-Q, our reports on Forms 10-K and 8-K, our other reports on Form 10-Q, our Proxy Statements on Schedule 14A and any other public statements that are made by us may prove to be incorrect. This may occur as a result of assumptions, which turn out to be inaccurate, or as a consequence of known or unknown risks and uncertainties. Many factors discussed in this Quarterly Report on Form 10-Q, certain of which are beyond our control, will be important in determining our future performance. Consequently, actual results may differ materially from those that might be anticipated from forward-looking statements. In light of these and other uncertainties, you should not regard the inclusion of any of our forward-looking statements in this Quarterly Report on Form 10-Q or other public communications as a representation by us that our plans and objectives will be achieved, and you should not place undue reliance on such forward-looking statements.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. However, your attention is directed to any further disclosures made on related subjects in our subsequent reports filed with the Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

Unless the context requires otherwise, references to "we," "us," "our," "NorthWestern Energy Group," "NorthWestern Energy," and "NorthWestern" refer specifically to NorthWestern Energy Group, Inc. and its subsidiaries.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

NORTHWESTERN ENERGY GROUP

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Revenues				
Electric	$ 324,254	$ 279,468	$ 686,308	$ 614,951
Gas	68,345	63,245	203,861	194,392
Total Revenues	392,599	342,713	890,169	809,343
Operating expenses				
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	89,823	75,271	235,388	213,468
Operating and maintenance	79,095	62,336	153,635	119,045
Administrative and general	42,356	33,773	88,475	75,130
Property and other taxes	50,101	48,168	100,505	91,408
Depreciation and depletion	66,978	62,379	133,809	124,779
Total Operating Expenses	328,353	281,927	711,812	623,830
Operating income	64,246	60,786	178,357	185,513
Interest expense, net	(40,332)	(36,254)	(80,248)	(72,765)
Other income, net	4,546	78	7,603	4,006
Income before income taxes	28,460	24,610	105,712	116,754
Income tax expense	(3,466)	(3,382)	(17,262)	(18,586)
Net Income	$ 24,994	$ 21,228	$ 88,450	$ 98,168
Average Common Shares Outstanding	61,509	61,381	61,485	61,360
Basic Earnings per Average Common Share	$ 0.41	$ 0.35	$ 1.44	$ 1.60
Diluted Earnings per Average Common Share	$ 0.40	$ 0.35	$ 1.43	$ 1.60
Dividends Declared per Common Share	$ 0.67	$ 0.66	$ 1.34	$ 1.32

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 24,994	$ 21,228	$ 88,450	$ 98,168
Other comprehensive income, net of tax:				
Foreign currency translation adjustment	(2)	4	(3)	5
Reclassification of net losses on derivative instruments	113	113	226	226
Total Other Comprehensive Income	111	117	223	231
Comprehensive Income	$ 25,105	$ 21,345	$ 88,673	$ 98,399

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands, except share data)

	June 30, 2026	December 31, 2025
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,180	$ 8,781
Restricted cash	20,920	21,957
Accounts receivable, net	168,782	209,751
Inventories	145,986	132,506
Regulatory assets	105,469	92,937
Prepaid expenses and other	36,312	38,010
Total current assets	**481,649**	**503,942**
Property, plant, and equipment, net	6,902,094	6,738,849
Goodwill	367,635	367,635
Regulatory assets	778,828	772,634
Other noncurrent assets	173,495	76,631
Total Assets	**$ 8,703,701**	**$ 8,459,691**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 1,708	$ 1,865
Current portion of long-term debt	44,996	104,967
Short-term borrowings	100,000	150,000
Accounts payable	114,802	129,633
Accrued expenses and other	294,896	272,373
Regulatory liabilities	26,644	38,613
Total current liabilities	**583,046**	**697,451**
Long-term finance leases	7,728	—
Long-term debt	3,442,174	3,181,040
Deferred income taxes	761,092	733,064
Noncurrent regulatory liabilities	692,026	678,861
Other noncurrent liabilities	322,298	283,535
Total Liabilities	**5,808,364**	**5,573,951**
Commitments and Contingencies (Note 11)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 65,006,266 and 61,513,596 shares, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	650	649
Treasury stock at cost	(99,035)	(97,503)
Paid-in capital	2,096,493	2,091,935
Retained earnings	903,067	896,720
Accumulated other comprehensive loss	(5,838)	(6,061)
Total Shareholders' Equity	**2,895,337**	**2,885,740**
Total Liabilities and Shareholders' Equity	**$ 8,703,701**	**$ 8,459,691**

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Six Months Ended June 30,	
	2026	2025
OPERATING ACTIVITIES:		
Net income	$ 88,450	$ 98,168
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and depletion	133,809	124,779
Amortization of debt issuance costs, premium, and deferred hedge gain	1,926	2,343
Stock-based compensation costs	4,088	4,168
Equity portion of allowance for funds used during construction	(4,587)	(4,066)
Deferred income taxes	14,406	16,746
Other adjustments	(41)	151
Changes in current assets and liabilities:		
Accounts receivable	40,967	32,841
Inventories	(13,480)	(2,458)
Other current assets	(5,410)	9,907
Accounts payable	(7,781)	(27,688)
Accrued expenses and other	22,571	(2,861)
Regulatory assets	(12,532)	(27,653)
Regulatory liabilities	(11,969)	(4,200)
Other noncurrent assets and liabilities	(17,185)	(8,576)
Cash Provided by Operating Activities	**233,232**	**211,601**
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(304,772)	(220,978)
Investment in debt & equity securities	(1,070)	(5,778)
Cash Used in Investing Activities	**(305,842)**	**(226,756)**
FINANCING ACTIVITIES:		
Dividends on common stock	(82,103)	(80,654)
Issuance of long-term debt	375,000	500,000
Repayment of short-term borrowings	(50,000)	—
Repayments on long-term debt	(60,000)	(300,000)
Line of credit repayments, net	(114,000)	(103,000)
Other financing activities, net	(1,925)	(3,660)
Cash Provided by Financing Activities	**66,972**	**12,686**
Decrease in Cash, Cash Equivalents, and Restricted Cash	(5,638)	(2,469)
Cash, Cash Equivalents, and Restricted Cash, beginning of period	30,738	29,017
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 25,100**	**$ 26,548**
Supplemental Cash Flow Information:		
Cash (received) paid during the period for:		
Production tax credits[1]	—	(8,255)
Interest	76,713	67,166
Significant non-cash transactions:		
Capital expenditures included in accounts payable	34,653	32,015

(1) Proceeds from production tax credits transferred are included in cash provided by operating activities within the Condensed Consolidated Statement of Cash Flows.

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Unaudited)

(in thousands, except per share data)

	Three Months Ended June 30,							
	Number of Common Shares	Number of Treasury Shares	Common Stock	Treasury Stock	Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at March 31, 2025	**64,870**	**3,497**	**$ 649**	**$ (97,935)**	**$2,086,594**	**$913,650**	**$ (6,590)**	**$ 2,896,368**
Net income	—	—	—	—	—	21,228	—	21,228
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	4	4
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Stock-based compensation	6	—	—	—	1,870	—	—	1,870
Issuance of shares	—	(8)	—	230	210	—	—	440
Dividends on common stock ($0.660 per share)	—	—	—	—	—	(40,347)	—	(40,347)
Balance at June 30, 2025	**64,876**	**3,489**	**$ 649**	**$ (97,705)**	**$2,088,674**	**$894,531**	**$ (6,473)**	**$ 2,879,676**
Balance at March 31, 2026	**65,001**	**3,498**	**$ 650**	**$ (99,186)**	**$2,094,232**	**$919,137**	**$ (5,949)**	**$ 2,908,884**
Net income	—	—	—	—	—	24,994	—	24,994
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(2)	(2)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Stock-based compensation	5	—	—	—	2,030	—	—	2,030
Issuance of shares	—	(5)	—	151	231	—	—	382
Dividends on common stock ($0.670 per share)	—	—	—	—	—	(41,064)	—	(41,064)
Balance at June 30, 2026	**65,006**	**3,493**	**650**	**(99,035)**	**2,096,493**	**903,067**	**(5,838)**	**2,895,337**

	Six Months Ended June 30,							
	Number of Common Shares	**Number of Treasury Shares**	**Common Stock**	**Treasury Stock**	**Paid in Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholders' Equity**
Balance at December 31, 2024	**64,811**	**3,490**	**$ 648**	**$ (97,394)**	**$ 2,084,133**	**$ 877,017**	**$ (6,704)**	**$ 2,857,700**
Net income	—	—	—	—	—	98,168	—	98,168
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	5	5
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	226	226
Stock-based compensation	65	—	1	(729)	4,142	—	—	3,414
Issuance of shares	—	(1)	—	418	399	—	—	817
Dividends on common stock ($1.320 per share)	—	—	—	—	—	(80,654)	—	(80,654)
Balance at June 30, 2025	**64,876**	**3,489**	**$ 649**	**$ (97,705)**	**$ 2,088,674**	**$ 894,531**	**$ (6,473)**	**$ 2,879,676**
Balance at December 31, 2025	**64,895**	**3,477**	**$ 649**	**$ (97,503)**	**$ 2,091,935**	**$ 896,720**	**$ (6,061)**	**$ 2,885,740**
Net income	—	—	—	—	—	88,450	—	88,450
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(3)	(3)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	226	226
Stock-based compensation	111	28	1	(1,874)	4,066	—	—	2,193
Issuance of shares	—	(12)	—	342	492	—	—	834
Dividends on common stock ($1.340 per share)	—	—	—	—	—	(82,103)	—	(82,103)
Balance at June 30, 2026	**65,006**	**3,493**	**650**	**(99,035)**	**2,096,493**	**903,067**	**(5,838)**	**2,895,337**

See Notes to Condensed Consolidated Financial Statements

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Reference is made to Notes to Financial Statements included in the NorthWestern Energy Group's Annual Report)
(Unaudited)

(1) Nature of Operations and Basis of Consolidation

NorthWestern Energy Group, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 850,300 customers in Montana, South Dakota, Nebraska and Yellowstone National Park, through its subsidiaries NorthWestern Corporation (NW Corp) and NorthWestern Energy Public Service Corporation (NWE Public Service). We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires us to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The unaudited Condensed Consolidated Financial Statements (Financial Statements) reflect all adjustments (which unless otherwise noted are normal and recurring in nature) that are, in our opinion, necessary to fairly present our financial position, results of operations and cash flows. The actual results for the interim periods are not necessarily indicative of the operating results to be expected for a full year or for other interim periods. Events occurring subsequent to June 30, 2026 have been evaluated as to their potential impact to the Financial Statements through the date of issuance.

The Financial Statements included herein have been prepared by NorthWestern, without audit, pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations; however, we believe that the condensed disclosures provided are adequate to make the information presented not misleading. We recommend that these Financial Statements be read in conjunction with the audited financial statements and related footnotes included in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025.

Supplemental Cash Flow Information

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Condensed Consolidated Balance Sheets that sum to the total of the same such amounts shown in the Condensed Consolidated Statements of Cash Flows (in thousands):

	June 30, 2026	December 31, 2025	June 30, 2025	December 31, 2024
Cash and cash equivalents	$ 4,180	$ 8,781	$ 2,936	$ 4,283
Restricted cash	20,920	21,957	23,612	24,734
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 25,100	$ 30,738	$ 26,548	$ 29,017

Goodwill

We completed our annual goodwill impairment test as of April 1, 2026, and no impairment was identified. We evaluated qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors, and overall financial performance) to determine whether it was more likely than not that the fair value of our reporting units was less than its carrying amount. Our evaluation of these factors concluded that it was not more likely than not that the fair value of our reporting units was less than its carrying amount and therefore no further testing was necessary.

(2) Pending Merger with Black Hills Corporation

On August 18, 2025, we entered into a Merger Agreement with Black Hills and River Merger Sub, Inc., a Delaware corporation and direct wholly owned subsidiary of Black Hills (Merger Sub). The Merger Agreement provides for an all-stock merger of equals between NorthWestern and Black Hills upon the terms and subject to the conditions set forth therein. The Merger Agreement provides for Merger Sub to merge with and into NorthWestern, with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of Black Hills, which would assume the new corporate name of Bright Horizon Energy as the resulting parent company of the combined corporate group. Under the provisions of ASC Topic 805, which requires the identification of an acquirer in a business combination, Black Hills is the accounting acquirer. Pursuant to the Merger Agreement, at the effective time of the Merger, each share of NorthWestern, par value $0.01 per share, issued and outstanding as of immediately prior to closing will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of Black Hills Common Stock.

In connection with this pending merger, we have incurred merger-related costs. During the three and six months ended June 30, 2026, we have incurred $3.3 million and $6.7 million, respectively, of merger-related costs, which are included in our Administrative and general expenses.

Regulatory and Shareholder Approvals

Our pending merger with Black Hills was unanimously approved by our board of directors and Black Hills' board of directors. In February 2026, the Form S-4, which contains joint proxy statement/prospectus for NorthWestern and Black Hills, was declared effective by the SEC. In April 2026, shareholders of each company voted to approve the Merger and the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act expired, permitting consummation of the transaction. In May 2026, the Federal Energy Regulatory Commission (FERC) and the Nebraska Public Service Commission (NPSC) each approved the Merger. In June 2026, the South Dakota Public Utilities Commission (SDPUC) approved the merger.

The completion of the Merger remains subject to the satisfaction or waiver of certain conditions to closing, including (1) subject to certain conditions, the receipt of certain regulatory approvals, including approval from the Montana Public Service Commission (MPSC) on such terms and conditions that would not result in a material adverse effect on Bright Horizon Energy; (2) the absence of any court order or regulatory injunction prohibiting the completion of the Merger; (3) the authorization for listing of shares of Black Hills Common Stock to be issued in the Merger on a mutually agreed stock exchange; (4) subject to specified materiality standards, the accuracy of the representations and warranties of each party; (5) compliance by each party in all material respects with its covenants; (6) the absence of a material adverse effect on each party; and (7) receipt of each party of an opinion relating to the anticipated tax-free treatment of the Merger.

We filed an application with the MPSC for approval of the Merger, and in April 2026, we reached a settlement agreement with certain key intervenors in Montana, which is subject to the approval by the MPSC. In May 2026, a hearing with the MPSC was held and we await their final order.

We anticipate the transaction closing by year-end 2026, subject to the satisfaction or waiver of certain closing conditions.

(3) Regulatory Matters

Montana Rate Review

In December 2025, the MPSC issued a final order approving our partial electric settlement agreement. The final order also suspended the 90/10 cost sharing mechanism of the Power Cost and Credit Adjustment Mechanism (PCCAM) on a temporary basis pending further review by the MPSC. Within this final order, the MPSC disallowed a portion of the capital costs related to the construction of Yellowstone County Generating Station (YCGS). As a result, in the fourth quarter of 2025 we recorded a $30.9 million non-cash charge for the regulatory disallowance. As of June 30, 2026, we have $3.6 million reserved within Regulatory liabilities on the Condensed Consolidated Balance Sheets for interim rates to be refunded to customers.

In January 2026, we filed a Motion for Reconsideration (Motion) as it relates to this final order. Among other things, our Motion requests that the MPSC reconsider their prudence conclusions regarding the capital costs associated with the construction of YCGS and clarification as to the effective date of the PCCAM sharing mechanism suspension, for which we have requested an effective date of July 1, 2025, to align with the PCCAM tracker year. Any subsequent modifications by the MPSC to their final order are expected to be reflected in our 2026 results.

Colstrip Acquisitions and Requests for Cost Recovery

In January 2023, and July 2024, we entered into definitive agreements with Avista Corporation (Avista) and Puget Sound Energy (Puget), respectively, to acquire their respective interests in Colstrip Units 3 and 4 for $0 and completed these acquisitions on January 1, 2026. Accordingly, we are responsible for the associated operating costs beginning on January 1, 2026, which we will not collect through utility base rates, until requested in a future Montana rate review. Puget and Avista will remain responsible for their respective pre-closing share of environmental, asset retirement obligations (AROs), and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommissioning and demolition costs associated with the existing facilities that comprise their interests.

While Puget and Avista remain contractually obligated for the pre-closing share of AROs, we remain the primary obligor. As such, as of June 30, 2026, we have recorded $2.8 million and $34.2 million within Accrued expenses and other and Other noncurrent liabilities, respectively, on the Condensed Consolidated Balance Sheets for these AROs, and we have recorded an indemnification asset of $2.8 million and $34.2 million with Prepaid expenses and other and Other noncurrent assets, respectively, on the Condensed Consolidated Balance Sheets.

Avista Interests - The 222 megawatts of generation capacity from Colstrip Units 3 and 4 acquired from Avista (Avista Interests) on January 1, 2026, was identified as a key element in our strategy to achieve resource adequacy for customers, as outlined in our 2023 Montana Integrated Resource Plan. Noting the costs associated with operating this resource are not currently reflected in utility customer rates, in August 2025, we filed a temporary PCCAM tariff waiver request with the MPSC that could provide a near-term cost-recovery mechanism to offset a portion of the approximately $18 million in annual incremental operating and maintenance costs associated with the Avista Interests. This waiver requested that the MPSC allow us to keep 100 percent of the net revenue associated with certain designated power sales contracts up to the amount of the operating and maintenance expenses we incur associated with our Avista Interests. Furthermore, the waiver request indicated that any net revenues from the designated contracts exceeding the operating and maintenance expenses associated with our Avista Interests would continue to flow back to retail customers. In January 2026, the MPSC approved our PCCAM tariff waiver request on an interim basis with final approval or denial subject to the ongoing PCCAM docket process.

During the three and six months ended June 30, 2026, power prices in the Pacific Northwest associated with these designated power sales contracts included within our PCCAM tariff waiver were insufficient to contribute to the recovery of the operating and maintenance expenses associated with the Avista Interests.

Puget Interests - The 370 megawatts of generation capacity from Colstrip Units 3 and 4 acquired from Puget (Puget Interests) on January 1, 2026, increases our ownership share of the facility to 55 percent and provides an increase in voting share in determining strategic direction and investment decisions at the facility. Unlike the Avista Interests, we do not currently need this capacity to serve existing customers in Montana. As such, the Puget Interests are held by our FERC regulated subsidiary to isolate the costs associated with this acquired interest from our Montana retail customers. While we expect our future opportunity to serve growing customer demand, including large-load customers, may be supported by this resource, in October 2025, we signed a contract to sell the dispatchable capacity and associated energy from the Puget Interests beginning January 1, 2026, through late 2027. Revenues from this agreement are expected to largely offset the estimated $30 million of annual incremental operating and maintenance costs associated with the Puget Interests. In addition, in October 2025, we submitted a request to the FERC for approval of cost-based rates for our subsidiary that will own the Puget Interests. In February 2026, the FERC approved both the cost based rates and the contract rates retroactive to January 1, 2026. In March 2026, two MPSC commissioners, in their individual capacity, filed a motion with the FERC requesting a rehearing that largely reiterated arguments previously rejected by the FERC. The FERC denied this motion by operation of law. In June 2026, the two MPSC commissioners appealed the decision to the Ninth Circuit. We have intervened in the case.

(4) Income Taxes

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate due to the regulatory impact of flowing through the federal and state tax benefit of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

During the three months ended June 30, 2026 income tax expense was $3.5 million compared to $3.4 million for the same period in 2025. For the three months ended June 30, 2026, the effective tax rate was 12.2% compared to 13.7% for the same period in 2025. The lower effective tax rate was primarily due to higher flow through repairs deductions partly offset by higher plant depreciation flow through items.

During the six months ended June 30, 2026 income tax expense was $17.3 million compared to $18.6 million for the same period in 2025. For the six months ended June 30, 2026, the effective tax rate was 16.3% compared to 15.9% for the same period in 2025. The higher effective tax rate was primarily due to higher plant depreciation flow through items and lower production tax credits, partly offset by higher flow through repairs deductions.

(5) Comprehensive Income (Loss)

The following tables display the components of Other Comprehensive Income (Loss), after-tax, and the related tax effects (in thousands):

	Three Months Ended					
	June 30, 2026			June 30, 2025		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (2)	$ —	$ (2)	$ 4	$ —	$ 4
Reclassification of net income on derivative instruments	153	(40)	113	153	(40)	113
Other comprehensive income (loss)	$ 151	$ (40)	$ 111	$ 157	$ (40)	$ 117

	Six Months Ended					
	June 30, 2026			June 30, 2025		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (3)	$ —	$ (3)	$ 5	$ —	$ 5
Reclassification of net income on derivative instruments	306	(80)	226	306	(80)	226
Other comprehensive income (loss)	$ 303	$ (80)	$ 223	$ 311	$ (80)	$ 231

Balances by classification included within accumulated other comprehensive loss (AOCL) on the Condensed Consolidated Balance Sheets are as follows, net of tax (in thousands):

	June 30, 2026	December 31, 2025
Foreign currency translation	$ 1,448	$ 1,451
Derivative instruments designated as cash flow hedges	(8,243)	(8,469)
Postretirement medical plans	957	957
Accumulated other comprehensive loss	$ (5,838)	$ (6,061)

The following tables display the changes in AOCL by component, net of tax (in thousands):

		Three Months Ended June 30, 2026			
	Affected Line Item in the Condensed Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,356)	$ 957	$ 1,450	$ (5,949)
Other comprehensive loss before reclassifications		—	—	(2)	(2)
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income (loss)		113	—	(2)	111
Ending balance		$ (8,243)	$ 957	$ 1,448	$ (5,838)

	Affected Line Item in the Condensed Consolidated Statements of Income	Three Months Ended June 30, 2025			
		Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,808)	$ 784	$ 1,434	$ (6,590)
Other comprehensive income before reclassifications		—	—	4	4
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income		113	—	4	117
Ending balance		$ (8,695)	$ 784	$ 1,438	$ (6,473)

	Affected Line Item in the Condensed Consolidated Statements of Income	Six Months Ended June 30, 2026			
		Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,469)	$ 957	$ 1,451	$ (6,061)
Other comprehensive loss before reclassifications		—	—	(3)	(3)
Amounts reclassified from AOCL	Interest Expense	226	—	—	226
Net current-period other comprehensive income (loss)		226	—	(3)	223
Ending balance		$ (8,243)	$ 957	$ 1,448	$ (5,838)

	Affected Line Item in the Condensed Consolidated Statements of Income	Six Months Ended June 30, 2025			
		Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,921)	$ 784	$ 1,433	$ (6,704)
Other comprehensive income before reclassifications		—	—	5	5
Amounts reclassified from AOCL	Interest Expense	226	—	—	226
Net current-period other comprehensive income		226	—	5	231
Ending balance		$ (8,695)	$ 784	$ 1,438	$ (6,473)

(6) Financing Activities

We exercised a five-year renewal option on a default supply procurement agreement, which we have recorded as a finance lease on our Condensed Consolidated Balance Sheets. As a result, the finance lease term was extended and will mature on June 30, 2031.

On April 9, 2026, we amended our existing NorthWestern Energy Group Term Loan Credit Agreement (NWE Group Term Loan) to extend the maturity date from April 10, 2026 to December 31, 2026. In May 2026, we repaid $50.0 million of this NWE Group Term Loan.

On April 28, 2026, NWE Public Service priced $150.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.51 percent maturing on June 15, 2036. We completed the issuance and sale of these bonds on June 15, 2026. Proceeds were utilized to redeem NWE Public Service's $60.0 million of 2.80 percent South Dakota First Mortgage Bonds due on June 15, 2026, to repay outstanding borrowings under our credit facility, and for general utility purposes.

On May 27, 2026, NW Corp entered into a $225.0 million secured Term Loan Credit Agreement (NW Corp Term Loan) with a maturity date of November 26, 2027. NW Corp's obligations under the NW Corp Term Loan are secured by $225.0 million of Montana First Mortgage Bonds issued to the administrative agent of the term loan facility. Borrowings may be made at a variable interest rate equal to the Secured Overnight Financing Rate plus an applicable margin as provided in the NW Corp Term Loan. Proceeds were used to repay a portion of NW Corp's outstanding revolving credit facility borrowings. The NW Corp Term Loan provides for prepayment of the principal and interest; however, amounts prepaid may not be reborrowed. The NW Corp Term Loan requires NW Corp to maintain a consolidated indebtedness to total capitalization ratio of 65 percent or less. It also contains covenants which, among other things, limit our ability to engage in any consolidation or merger (except for our pending merger with Black Hills) or otherwise liquidate or dissolve, dispose of property, and restricts certain affiliate transactions.

(7) Segment Information

Our reportable segments are engaged in the electric and natural gas utility businesses.

Our Chief Operating Decision Maker (CODM), who is our Chief Executive Officer, uses segment net income to evaluate if our operating segments are earning their authorized rate of return and in the annual budget and forecasting process. Our CODM also uses segment net income to determine how to allocate capital resources between our operating segments and when to allocate the resources necessary to file for rate reviews. Segment asset and capital expenditure information is not provided for our reportable segments. As an integrated electric and gas utility, we operate significant assets that are not dedicated to a specific reportable segment.

Financial data for the reportable segments are as follows (in thousands):

Three Months Ended June 30, 2026	**Electric**	**Gas**	**Total**
Operating revenues	$ 324,254	$ 68,345	$ 392,599
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	72,836	16,987	89,823
Operating, general, and administrative	91,739	25,551	117,290
Property and other taxes	39,056	11,044	50,100
Depreciation and depletion	55,562	11,416	66,978
Interest expense, net	(30,589)	(8,086)	(38,675)
Other income, net	2,941	1,167	4,108
Income tax (expense) benefit	(5,451)	304	(5,147)
Segment net income (loss)	$ 31,962	$ (3,268)	$ 28,694
Reconciliation to consolidated net income			
Other, net[1]			(3,700)
Consolidated net income			$ 24,994

Three Months Ended June 30, 2025	Electric	Gas	Total
Operating revenues	$ 279,468	$ 63,245	$ 342,713
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	59,603	15,668	75,271
Operating, general, and administrative	73,615	22,773	96,388
Property and other taxes	37,318	10,850	48,168
Depreciation and depletion	52,387	9,992	62,379
Interest expense, net	(27,562)	(7,297)	(34,859)
Other income, net	121	456	577
Income tax (expense) benefit	(4,230)	201	(4,029)
Segment net income (loss)	$ 24,874	$ (2,678)	$ 22,196
Reconciliation to consolidated net income			
Other, net(1)			(968)
Consolidated net income			$ 21,228

Six Months Ended June 30, 2026	Electric	Gas	Total
Operating revenues	$ 686,308	$ 203,861	$ 890,169
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	163,111	72,277	235,388
Operating, general, and administrative	181,340	52,682	234,022
Property and other taxes	78,267	22,196	100,463
Depreciation and depletion	111,031	22,778	133,809
Interest expense, net	(60,774)	(15,957)	(76,731)
Other income, net	4,486	1,791	6,277
Income tax expense	(16,934)	(2,831)	(19,765)
Segment net income	$ 79,337	$ 16,931	$ 96,268
Reconciliation to consolidated net income			
Other, net(1)			(7,818)
Consolidated net income			$ 88,450

Six Months Ended June 30, 2025	Electric	Gas	Total
Operating revenues	$ 614,951	$ 194,392	$ 809,343
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	152,355	61,113	213,468
Operating, general, and administrative	146,094	47,943	194,037
Property and other taxes	70,604	20,645	91,249
Depreciation and depletion	104,875	19,904	124,779
Interest expense, net	(55,318)	(14,331)	(69,649)
Other income, net	2,611	1,547	4,158
Income tax expense	(14,102)	(4,226)	(18,328)
Segment net income	$ 74,214	$ 27,777	$ 101,991
Reconciliation to consolidated net income			
Other, net(1)			(3,823)
Consolidated net income			$ 98,168

(1) Consists of unallocated corporate costs, including merger-related costs, and certain limited unregulated activity within the energy industry.

(8) Revenue from Contracts with Customers

Nature of Goods and Services

We provide retail electric and natural gas services to three primary customer classes. Our largest customer class consists of residential customers, which includes single private dwellings and individual apartments. Our commercial customers consist primarily of main street businesses, and our industrial customers consist primarily of manufacturing and processing businesses that turn raw materials into products.

Electric Segment - Our regulated electric utility business primarily provides generation, transmission, and distribution services to customers in our Montana and South Dakota jurisdictions. We recognize revenue when electricity is delivered to the customer. Payments on our tariff-based sales are generally due 0-30 days after the billing date.

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to customers in our Montana, South Dakota, and Nebraska jurisdictions. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff-based sales are generally due 0-30 days after the billing date.

Disaggregation of Revenue

The following tables disaggregate our revenue by major source and customer class (in thousands):

	Three Months Ended					
	June 30, 2026			June 30, 2025		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 98,447	$ 19,711	$ 118,158	$ 81,824	$ 17,968	$ 99,792
South Dakota	17,983	5,776	23,759	16,235	5,566	21,801
Nebraska	—	4,196	4,196	—	4,523	4,523
Residential	**116,430**	**29,683**	**146,113**	**98,059**	**28,057**	**126,116**
Montana	110,833	12,211	123,044	93,910	10,499	104,409
South Dakota	30,341	4,141	34,482	27,737	3,920	31,657
Nebraska	—	1,994	1,994	—	2,346	2,346
Commercial	**141,174**	**18,346**	**159,520**	**121,647**	**16,765**	**138,412**
Industrial	10,831	844	11,675	9,888	144	10,032
Lighting, governmental, irrigation, and interdepartmental	14,144	268	14,412	9,421	270	9,691
Total Retail Revenues	**282,579**	**49,141**	**331,720**	**239,015**	**45,236**	**284,251**
Regulatory Amortization	(3,645)	5,925	2,280	10,325	5,189	15,514
Transmission	29,141	—	29,141	28,147	—	28,147
Transportation, wholesale and other	16,179	13,279	29,458	1,981	12,820	14,801
Total Revenues	**$ 324,254**	**$ 68,345**	**$ 392,599**	**$ 279,468**	**$ 63,245**	**$ 342,713**

	Six Months Ended					
	June 30, 2026			June 30, 2025		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 218,885	$ 67,849	$ 286,734	$ 196,801	$ 69,386	$ 266,187
South Dakota	41,212	20,300	61,512	38,527	21,136	59,663
Nebraska	—	15,357	15,357	—	17,732	17,732
Residential	**260,097**	**103,506**	**363,603**	**235,328**	**108,254**	**343,582**
Montana	217,315	39,088	256,403	190,862	37,257	228,119
South Dakota	61,738	15,895	77,633	57,051	15,095	72,146
Nebraska	—	8,500	8,500	—	9,787	9,787
Commercial	**279,053**	**63,483**	**342,536**	**247,913**	**62,139**	**310,052**
Industrial	22,695	1,635	24,330	19,988	628	20,616
Lighting, governmental, irrigation, and interdepartmental	19,653	792	20,445	14,114	861	14,975
Total Retail Revenues	**581,498**	**169,416**	**750,914**	**517,343**	**171,882**	**689,225**
Regulatory Amortization	6,426	4,924	11,350	38,015	(4,247)	33,768
Transmission	60,112	—	60,112	54,703	—	54,703
Transportation, wholesale and other	38,272	29,521	67,793	4,890	26,757	31,647
Total Revenues	**$ 686,308**	**$ 203,861**	**$ 890,169**	**$ 614,951**	**$ 194,392**	**$ 809,343**

(9) Earnings Per Share

Basic earnings per share are computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution of common stock equivalent shares that could occur if unvested shares were to vest. Common stock equivalent shares are calculated using the treasury stock method, as applicable. The dilutive effect is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding plus the effect of the outstanding unvested restricted stock and performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

	Three Months Ended	
	June 30, 2026	June 30, 2025
Basic computation	61,508,960	61,380,777
Dilutive effect of:		
Performance and restricted share awards[1]	265,634	103,169
Diluted computation	61,774,594	61,483,946

	Six Months Ended	
	June 30, 2026	June 30, 2025
Basic computation	61,484,991	61,360,252
Dilutive effect of:		
Performance and restricted share awards[1]	218,440	95,733
Diluted computation	61,703,431	61,455,985

(1) Performance share awards are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the award.

As of June 30, 2026, there were no shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations, compared to 68,107 shares as of June 30, 2025.

(10) Employee Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. Net periodic benefit cost (credit) for our pension and other postretirement plans consists of the following (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2026	2025	2026	2025
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 1,145	$ 1,167	$ 48	$ 66
Interest cost	2,853	6,104	93	129
Expected return on plan assets	(2,902)	(5,734)	(403)	(355)
Recognized actuarial gain	—	—	(182)	(68)
Net periodic benefit cost (credit)	$ 1,096	$ 1,537	$ (444)	$ (228)

	Pension Benefits		Other Postretirement Benefits	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 2,243	$ 2,362	$ 102	$ 128
Interest cost	5,744	12,149	195	256
Expected return on plan assets	(5,825)	(11,476)	(806)	(709)
Recognized actuarial gain	—	—	(343)	(138)
Net periodic benefit cost (credit)	$ 2,162	$ 3,035	$ (852)	$ (463)

We contributed $4.9 million to our pension plans during the six months ended June 30, 2026. We expect to contribute an additional $6.6 million to our pension plans during the remainder of 2026.

(11) Commitments and Contingencies

Parent Guarantee

NorthWestern Energy Group, Inc. has guaranteed the contractual obligations of its wholly-owned subsidiary, NorthWestern Colstrip 370Pu, LLC (NW Colstrip 370), to its counterparty to an agreement for the sale of capacity and energy from our recently acquired 370 megawatt ownership interest in the Colstrip facility. The guarantee exists during the January 2026 through September 2027 term of the agreement. The guarantee is unconditional and irrevocable, covering all payment obligations of the subsidiary under the contract up to a maximum amount of $15.0 million. The guarantee is triggered in an event where NW Colstrip 370 fails to pay any amounts that could come due under the agreement. As of June 30, 2026, no demand has been made under the guarantee and management believes that risk of material payment under this guarantee is remote.

ENVIRONMENTAL LIABILITIES AND REGULATION

The circumstances set forth in Note 20 - Commitments and Contingencies to the financial statements included in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025 appropriately represent, in all material respects, the current status of our environmental liabilities and regulation.

LEGAL PROCEEDINGS

We are subject to various legal proceedings, governmental audits and claims that arise in the ordinary course of business. In our opinion, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Utility Margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. We define Utility Margin as Operating Revenues less fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion) as presented in our Condensed Consolidated Statements of Income. This measure differs from the GAAP definition of Gross Margin due to the exclusion of Operating and maintenance, Property and other taxes, and Depreciation and depletion expenses, which are presented separately in our Condensed Consolidated Statements of Income. The following discussion includes a reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure.

We believe that Utility Margin provides a useful measure for investors and other financial statement users to analyze our financial performance in that it excludes the effect on total revenues caused by volatility in energy costs and associated regulatory mechanisms. This information is intended to enhance an investor's overall understanding of results. Under our various state regulatory mechanisms, as detailed below, our supply costs are generally collected from customers. In addition, Utility Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow for recovery of operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates and other factors impact our results of operations. Our Utility Margin measure may not be comparable to that of other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

OVERVIEW

NorthWestern Energy Group, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 850,300 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. Our operations in Montana and Yellowstone National Park are conducted through our subsidiary, NW Corp, and our operations in South Dakota and Nebraska are conducted through our subsidiary, NWE Public Service. For a discussion of NorthWestern's business strategy, see Management's Discussion and Analysis of Financial Condition and Results of Operations in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025.

On August 18, 2025, we entered into the Merger Agreement with Black Hills and Merger Sub that provides for an all-stock merger of equals between NorthWestern and Black Hills. The Merger Agreement provides for Merger Sub to merge with and into NorthWestern, with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of Black Hills, which would assume a new corporate name of Bright Horizon Energy as the resulting parent company of the combined corporate group. The Merger will combine the strengths of both companies, resulting in an organization with greater scale, financial stability, and operational expertise. It is designed to create a stronger, more resilient energy company focused on delivering safe, reliable, and affordable energy solutions to customers. Under the provisions of Accounting Standards Codification Topic 805, which requires the identification of an acquirer in a business combination, Black Hills is the accounting acquirer. Pursuant to the Merger Agreement, at the effective time of the Merger, each share of common stock of NorthWestern issued and outstanding as of immediately prior to closing will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of Black Hills Common Stock. Subject to the approval of the Merger from the MPSC and satisfaction or waiver of the other remaining closing conditions, we anticipate the transaction closing by year-end 2026. See Note 2 - Pending Merger with Black Hills Corporation to the Condensed Consolidated Financial Statements included herein for additional information regarding this pending Merger.

We work to deliver safe, reliable, and innovative energy solutions that create value for customers, communities, employees, and investors. We do this by providing low-cost and reliable service performed by highly-adaptable and skilled employees. We are focused on delivering long-term shareholder value through:

- Infrastructure investment focused on a stronger and smarter grid to improve the customer experience, while enhancing grid reliability and safety. This includes automation in customer meters, distribution and substations that enables the use of proven new technologies.
- Investing in and integrating supply resources that balance reliability, cost, capacity, and sustainability considerations with more predictable long-term commodity prices.

- Continually improving our operating efficiency. Financial discipline is essential to earning our authorized return on invested capital and maintaining a strong balance sheet, stable cash flows, and quality credit ratings to continue to attract cost-effective capital for future investment.

We expect to pursue these investment opportunities and manage our business in a manner that allows us to be flexible in adjusting to changing economic conditions by adjusting the timing and scale of the projects.

We are committed to providing customers with reliable and affordable electric and natural gas services while also being good stewards of the environment. Towards this end, our efforts towards a carbon-free future are outlined through our goal to achieve net zero carbon emissions by 2050.

As you read this discussion and analysis, refer to our Condensed Consolidated Statements of Income, which present the results of our operations for the three and six months ended June 30, 2026 and 2025.

HOW WE PERFORMED AGAINST OUR SECOND QUARTER 2025 RESULTS

	Three Months Ended June 30, 2026 vs. 2025		
	Income Before Income Taxes	Income Tax (Expense) Benefit[3]	Net Income
		(in millions)	
Second Quarter, 2025	**$ 24.6**	**$ (3.4)**	**$ 21.2**
*Variance in **revenue** and fuel, purchased supply, and direct transmission expense[1] items impacting net income:*			
Rates	13.8	(3.5)	10.3
Electric retail volumes	7.3	(1.8)	5.5
Electric margin from the acquisition of the Colstrip Puget Interests	4.7	(1.2)	3.5
Natural gas retail volumes	3.5	(0.9)	2.6
Production tax credits, offset within income tax expense	1.4	(1.4)	—
Electric transmission revenue	1.0	(0.3)	0.7
Non-recoverable Montana electric supply costs	0.8	(0.2)	0.6
Natural gas production step down	(0.4)	0.1	(0.3)
Montana property tax tracker collections	(0.2)	0.1	(0.1)
Other	1.1	(0.3)	0.8
*Variance in **expense** items[2] impacting net income:*			
Operating, maintenance, and administrative, excluding merger-related costs	(16.7)	4.2	(12.5)
Depreciation	(4.6)	1.2	(3.4)
Interest expense	(4.0)	1.0	(3.0)
Merger-related costs	(3.3)	0.7	(2.6)
Property and other taxes not recoverable within trackers	(2.0)	0.5	(1.5)
Other	1.5	1.7	3.2
Second Quarter, 2026	**$ 28.5**	**$ (3.5)**	**$ 25.0**
Change in Net Income			**$ 3.8**

(1) Exclusive of depreciation and depletion shown separately below
(2) Excluding fuel, purchased supply, and direct transmission expense
(3) Income tax expense calculation on reconciling items assumes a blended federal plus state effective tax rate of 25.3 percent.

Consolidated net income for the three months ended June 30, 2026 was $25.0 million as compared with $21.2 million for the same period in 2025. This increase was primarily due to new rates and retail volumes. These were offset in part by operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, depreciation expense, and interest expense.

SIGNIFICANT TRENDS AND REGULATION

Refer to the NorthWestern Energy Group Annual Report on the Form 10-K for the year ended December 31, 2025 for disclosure of the significant trends and regulations that could have a significant impact on our business. These significant trends and regulations have not changed materially since such disclosure, except as follows:

Montana Rate Review

In December 2025, the MPSC issued a final order approving our partial electric settlement agreement. The final order also suspended the 90/10 cost sharing mechanism of the Power Cost and Credit Adjustment Mechanism (PCCAM) on a temporary basis pending further review by the MPSC. Within this final order, the MPSC disallowed a portion of the capital costs related to the construction of Yellowstone County Generating Station (YCGS). As a result, in the fourth quarter of 2025 we recorded a $30.9 million non-cash charge for the regulatory disallowance.

In January 2026, we filed a Motion for Reconsideration (Motion) as it relates to this final order. Among other things, our Motion requests that the MPSC reconsider their prudence conclusions regarding the capital costs associated with the construction of YCGS and clarification as to the effective date of the PCCAM sharing mechanism suspension, for which we have requested an effective date of July 1, 2025, to align with the PCCAM tracker year. Any subsequent modifications by the MPSC to their final order are expected to be reflected in our 2026 results.

Montana Large New Load Tariff Rule

In March 2026, we filed an application with the MPSC requesting approval of a Large New Load tariff rule (LNL Rule) to establish requirements and contract terms for providing electric service to bundled customers with new or expanded loads of five megawatts or greater, including data centers and other energy-intensive operations. This filing establishes a framework governing agreements between us and large new load customers and is intended to address the costs and operational considerations associated with serving those loads while protecting existing customers from cost shifting and other adverse impacts. Under this proposed framework, for the largest commitments, 50 megawatts or greater, we would file the executed Electric Service Agreement with the MPSC for review and approval before service begins. For customers with loads between 5 and 49 megawatts, the tariff's standardized process and mandatory protections apply, but individual agreements do not require case-specific MPSC approval filings. This application initiates a public regulatory proceeding that will include opportunities for review and public comment consistent with MPSC procedures.

Data Center Development

As previously disclosed, we have signed development agreements with both Sabey Data Centers and Atlas Power Holdings LLC to provide electric supply services for data centers being developed in Montana. In April 2026, we signed a development agreement with Quantica Infrastructure to evaluate the transmission infrastructure and generation resources needed to support their proposed need. The combined energy service requirement associated with these development agreements is currently expected to be 150 megawatts beginning in late 2027, with growth of up to approximately 1,500 megawatts or more by 2030. We are working with each of these parties to execute electric service agreements.

Resources and regulatory mechanisms, such as the LNL Rule discussed above, to be utilized for serving these requests are pending further evaluation and regulatory considerations.

Colstrip Acquisitions and Requests for Cost Recovery

As previously disclosed, we entered into definitive agreements with Avista and Puget to acquire their respective interests in Colstrip Units 3 and 4 for $0 and completed these acquisitions on January 1, 2026. Accordingly, we are responsible for the associated operating costs beginning on January 1, 2026, which we will not collect through utility base rates until requested in a future Montana rate review. Puget and Avista will remain responsible for their respective pre-closing share of environmental, AROs, and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommissioning and demolition costs associated with the existing facilities that comprise their interests.

Avista Interests - The 222 megawatts of generation capacity from Colstrip Units 3 and 4 acquired from Avista (Avista Interests) on January 1, 2026, was identified as a key element in our strategy to achieve resource adequacy for customers, as outlined in our 2023 Montana Integrated Resource Plan. Noting the costs associated with operating this resource are not currently reflected in utility customer rates, in August 2025, we filed a temporary PCCAM tariff waiver request with the MPSC that could provide a near-term cost-recovery mechanism to offset a portion of the approximately $18.0 million in annual incremental operating and maintenance costs associated with the Avista Interests. This waiver requested that the MPSC allow us to keep 100 percent of the net revenue associated with certain designated power sales contracts up to the amount of the operating and maintenance expenses we incur associated with our Avista Interests. Furthermore, the waiver request indicated that any net revenues from the designated contracts exceeding the operating and maintenance expenses associated with our Avista Interests would continue to flow back to retail customers. In January 2026, the MPSC approved our PCCAM tariff waiver request on an interim basis with final approval or denial subject to the ongoing PCCAM docket process.

During the three and six months ended June 30, 2026, power prices in the Pacific Northwest associated with these designated power sales contracts included within our PCCAM tariff waiver were insufficient to contribute to the recovery of the operating and maintenance expenses associated with the Avista Interests.

Puget Interests - The 370 megawatts of generation capacity from Colstrip Units 3 and 4 acquired from Puget (Puget Interests) on January 1, 2026, increases our ownership share of the facility to 55 percent and provides an increase in voting share in determining strategic direction and investment decisions at the facility. Unlike the Avista Interests, we do not currently need this capacity to serve existing customers in Montana. As such, the Puget Interests are held by our FERC regulated subsidiary to isolate the costs associated with this acquired interest from our Montana retail customers. While we expect our future opportunity to serve growing customer demand, including large-load customers, may be supported by this resource, in October 2025, we signed a contract to sell the dispatchable capacity and associated energy from the Puget Interests beginning January 1, 2026, through late 2027. Revenues from this agreement are expected to largely offset the estimated $30.0 million of annual incremental operating and maintenance costs associated with the Puget Interests. In addition, in October 2025, we submitted a request to the FERC for approval of cost-based rates for our subsidiary that will own the Puget Interests. In February 2026, the FERC approved both the cost-based rates and the contract rates retroactive to January 1, 2026. In March 2026, two MPSC commissioners, in their individual capacity, filed a motion with the FERC requesting a rehearing that largely reiterated arguments previously rejected by the FERC. The FERC denied this motion by operation of law. In June 2026, the two MPSC commissioners appealed the decision to the Ninth Circuit. We have intervened in the case.

Generation Capacity in South Dakota

The Southwest Power Pool (SPP) has recently updated its resource accreditation and planning reserve margin (PRM) requirements in response to growing reliability concerns. As a result, SPP is requiring additional accredited capacity by 2030 to meet the updated PRM targets. In October 2025, we submitted a project with the SPP under their Expedited Resource Adequacy Study program for the construction of a 131 MW natural gas generating facility located in Aberdeen, South Dakota, to meet regional capacity needs by 2030. Anticipated costs for this project are approximately $300.0 million. As of June 30, 2026, we have recorded $42.3 million within Other noncurrent assets on the Condensed Consolidated Balance Sheets for non-refundable milestone payments to secure the turbines that will be used at this facility.

Regional Transmission Development Activities

In December 2024, we signed a nonbinding memorandum of understanding (MOU) with North Plains Connector LLC, a wholly owned subsidiary of Grid United, to own 10 percent (300 megawatts) of the NPC Consortium project. The project is entering the permitting phase. Currently, construction is planned to commence in 2028, subject to receipt of regulatory approvals, with the project expected to be operational by 2032. Under the terms of the MOU, Grid United will continue to fund the development of the NPC and we will make our investment decision when the regulatory approvals and permits are in place. The project is a critical infrastructure investment that aligns with our commitment to providing reliable and affordable energy to our customers while also supporting broader grid resilience efforts in the region.

We have also entered into a nonbinding letter of intent with Grid United to continue transmission development to further enhance the grid through the southwest corridor of Montana. Development to expand the southwest corridor of Montana through grid build out would represent a significant step in enhancing connectivity between Montana and the broader Western energy market - bolstering grid reliability, allowing for critical import capability, and enabling customers to access and benefit from emerging energy markets in the West.

South Dakota Wildfire Risk Mitigation

The South Dakota Legislature approved Senate Bill 36, and the Governor signed this bill into law in March 2026. It precludes common law strict liability claims for utility operations alleged to have caused wildfire-related damages; establishes a statutory standard of care, supplanting common law causes of action and other theories of recovery; and creates a rebuttable presumption that a valid and current wildfire mitigation plan is reasonable preparation for, and mitigation of, wildfire risk. The legislation also defines the availability of damages by allowing noneconomic personal injury damages only when there is bodily injury and punitive damages only when an injured party proves by clear and convincing evidence that a qualified utility acted with willful and wanton misconduct and the qualified utility's willful and wanton misconduct was the actual and proximate cause of damages to the plaintiff. We anticipate filing our wildfire mitigation plan with the SDPUC in the third quarter of 2026.

RESULTS OF OPERATIONS

Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. The overall consolidated discussion is followed by a detailed discussion of utility margin by segment.

Factors Affecting Results of Operations

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. In addition, various regulatory agencies approve the prices for electric and natural gas utility service within their respective jurisdictions and regulate our ability to recover costs from customers.

Revenues are also impacted by customer growth and usage, the latter of which is primarily affected by weather and the impact of energy efficiency initiatives and investment. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect based on the number of customers, temperature variances, and the amount of electricity or natural gas historically used per degree of temperature. Degree-day, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees, is used to estimate the amount of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

Fuel, purchased supply and direct transmission expenses are costs directly associated with the generation and procurement of electricity and natural gas. These costs are generally collected in rates from customers and may fluctuate substantially with market prices and customer usage.

Operating and maintenance expenses are costs associated with the ongoing operation of our vertically-integrated utility facilities which provide electric and natural gas utility products and services to our customers. Among the most significant of these costs are those associated with direct labor and supervision, repair and maintenance expenses, and contract services. These costs are normally fairly stable across broad volume ranges and therefore do not normally increase or decrease significantly in the short term with increases or decreases in volumes.

OVERALL CONSOLIDATED RESULTS

Three Months Ended June 30, 2026 Compared with the Three Months Ended June 30, 2025

Consolidated net income for the three months ended June 30, 2026 was $25.0 million as compared with $21.2 million for the same period in 2025. This increase was primarily due to new rates and retail volumes. These were offset in part by operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, depreciation expense, and interest expense.

Consolidated gross margin for the three months ended June 30, 2026 was $106.6 million as compared with $94.5 million in 2025, an increase of $12.1 million, or 12.8 percent. This increase was primarily due to new rates and retail volumes. These were offset in part by higher operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, and depreciation expense.

	Electric		Natural Gas		Total	
	2026	2025	2026	2025	2026	2025
			(in millions)			
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 324.2	$ 279.4	$ 68.4	$ 63.3	$ 392.6	$ 342.7
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	72.8	59.6	17.0	15.7	89.8	75.3
Less: Operating and maintenance	63.6	48.6	15.5	13.7	79.1	62.3
Less: Property and other taxes	39.1	37.3	11.0	10.9	50.1	48.2
Less: Depreciation and depletion	55.6	52.4	11.4	10.0	67.0	62.4
Gross Margin	**93.1**	**81.5**	**13.5**	**13.0**	**106.6**	**94.5**
Add back: Operating and maintenance	63.6	48.6	15.5	13.7	79.1	62.3
Add back: Property and other taxes	39.1	37.3	11.0	10.9	50.1	48.2
Add back: Depreciation and depletion	55.6	52.4	11.4	10.0	67.0	62.4
Utility Margin[(1)]	**$ 251.4**	**$ 219.8**	**$ 51.4**	**$ 47.6**	**$ 302.8**	**$ 267.4**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Three Months Ended June 30,			
	2026	2025	Change	% Change
	(dollars in millions)			
Utility Margin				
Electric	$ 251.4	$ 219.8	$ 31.6	14.4 %
Natural Gas	51.4	47.6	3.8	8.0
Total Utility Margin[(1)]	**$ 302.8**	**$ 267.4**	**$ 35.4**	**13.2 %**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated utility margin for the three months ended June 30, 2026 was $302.8 million as compared with $267.4 million for the same period in 2025, an increase of $35.4 million, or 13.2 percent. Primary components of the change in utility margin include the following (in millions):

	Utility Margin 2026 vs. 2025
Utility Margin Items Impacting Net Income	
Base rates	$ 13.8
Electric retail volumes	7.3
Electric margin from the acquisition of the Puget Interests	4.7
Natural gas retail volumes (including a $2.0 million increase due to acquisition of Energy West Operations)	3.5
Electric transmission revenue	1.0
Non-recoverable Montana electric supply costs	0.8
Natural gas production step down	(0.4)
Montana property tax tracker collections	(0.2)
Other	1.1
Change in Utility Margin Items Impacting Net Income	**31.6**
Utility Margin Items Offset Within Net Income	
Operating expenses recovered in revenue, offset in operating and maintenance expense	2.4
Production tax credits, offset in income tax expense	1.4
Change in Utility Margin Items Offset Within Net Income	**3.8**
Increase in Consolidated Utility Margin[(1)]	**$ 35.4**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Electric retail volumes were impacted by favorable weather in South Dakota and customer growth in all jurisdictions, partly offset by unfavorable weather in Montana. Natural gas retail volumes were impacted by favorable weather in Montana and South Dakota, the acquisition of the Energy West operations in July 2025, and customer growth, partly offset by unfavorable weather in Nebraska.

Under the PCCAM, net supply costs higher or lower than the PCCAM base rate (PCCAM Base) (excluding qualifying facility (QF) costs) were allocated 90 percent to Montana customers and 10 percent to shareholders. Effective February 1, 2026 the cost sharing mechanism of the PCCAM was suspended on an interim basis pending further review by the MPSC. For the three months ended June 30, 2025, we recorded a decrease in pre-tax earnings of $0.8 million (10 percent of the PCCAM Base cost variance).

	Three Months Ended June 30,			
	2026	2025	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 79.1	$ 62.3	$ 16.8	27.0 %
Administrative and general	42.4	33.8	8.6	25.4
Property and other taxes	50.1	48.2	1.9	3.9
Depreciation and depletion	67.0	62.4	4.6	7.4
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 238.6**	**$ 206.7**	**$ 31.9**	**15.4 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $238.6 million for the three months ended June 30, 2026, as compared with $206.7 million for the three months ended June 30, 2025. Primary components of the change include the following (in millions):

	Operating Expenses 2026 vs. 2025
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income	
Electric generation maintenance (Including $6.4 million and $3.7 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)	$ 9.0
Depreciation expense due to plant additions and higher depreciation rates	4.6
Merger-related costs, including consulting and legal fees	3.3
Wildfire mitigation expense, partly offset by higher base revenues	2.6
Property and other taxes not recoverable within trackers	2.0
Labor and benefits	1.7
Technology implementation and maintenance expenses	0.8
Insurance expense	0.3
Uncollectible accounts	0.2
Other	2.1
Change in Items Impacting Net Income	**26.6**
Operating Expenses Offset Within Net Income	
Deferred compensation, offset in other income	3.0
Operating and maintenance expenses recovered in trackers, offset in revenue	2.4
Property and other taxes recovered in trackers, offset in revenue	(0.1)
Change in Items Offset Within Net Income	**5.3**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 31.9**

We estimate property taxes throughout each year, and update those estimates based on valuation reports received from the Montana Department of Revenue. Under Montana law, we are allowed to track the increases and decreases in the actual level of state and local taxes and fees and adjust our rates to recover the increase or decrease between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit.

Consolidated operating income for the three months ended June 30, 2026 was $64.2 million as compared with $60.8 million in the same period of 2025. This increase was primarily due to new rates and retail volumes. These were offset in part by operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, and depreciation expense.

Consolidated interest expense was $40.3 million for the three months ended June 30, 2026 as compared with $36.3 million for the same period of 2025. This increase was due to higher borrowings and interest rates partly offset by higher capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated other income was $4.5 million for the three months ended June 30, 2026 as compared with $0.1 million for the same period of 2025. This increase was primarily due to an increase in the value of deferred shares held in trust for deferred compensation, a prior year $1.0 million expense accrual related to an estimated penalty for the previously disclosed Community Renewable Energy Project (CREP) informed by a MPSC ruling, and higher capitalization of AFUDC.

Consolidated income tax expense was $3.5 million for the three months ended June 30, 2026 as compared to $3.4 million for the same period of 2025. Our effective tax rate for the three months ended June 30, 2026 was 12.2% as compared with 13.7% for the same period in 2025.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (dollars in millions):

	Three Months Ended June 30,			
	2026		2025	
	(in dollars)	(in percent)	(in dollars)	(in percent)
Income before income taxes	$ 28.5		$ 24.6	
Income tax calculated at federal statutory rate	6.0	21.0 %	5.2	21.0 %
State income tax, net of federal provision	0.4	1.4	0.1	0.4
Tax Credits				
Production tax credits	(0.6)	(2.1)	(0.6)	(2.4)
Impact of utility ratemaking on income taxes				
Flow-through repairs deductions	(4.4)	(15.4)	(2.8)	(11.4)
Amortization of excess deferred income taxes	(0.6)	(2.1)	(0.1)	(0.4)
AFUDC, net	(0.2)	(0.7)	(0.1)	(0.4)
Plant and depreciation of flow through items	2.8	9.8	1.5	6.1
Nontaxable and nondeductible items	0.2	0.7	(0.3)	(1.2)
Other	(0.1)	(0.4)	0.5	2.0
	(2.5)	(8.8)	(1.8)	(7.3)
Income Tax Expense and Effective Tax Rate	$ 3.5	12.2 %	$ 3.4	13.7 %

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

Six Months Ended June 30, 2026 Compared with the Six Months Ended June 30, 2025

Consolidated net income for the six months ended June 30, 2026 was $88.5 million as compared with $98.2 million for the same period in 2025. This decrease was primarily due to retail volumes, Montana property tax collections, operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, depreciation expense, and interest expense. These were offset in part by new rates, lower non-recoverable Montana electric supply costs, and transmission revenues.

Consolidated gross margin for the six months ended June 30, 2026 was $266.9 million as compared with $260.9 million in 2025, an increase of $6.0 million, or 2.3 percent. This increase was primarily due to new rates, lower non-recoverable Montana electric supply costs, and transmission revenues. These were offset in part by retail volumes, Montana property tax collections, operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, and depreciation expense.

	Electric		Natural Gas		Total	
	2026	2025	2026	2025	2026	2025
	(in millions)					
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 686.3	$ 615.0	$ 203.9	$ 194.4	$ 890.2	$ 809.4
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	163.1	152.4	72.3	61.1	235.4	213.5
Less: Operating and maintenance	122.9	91.2	30.7	27.8	153.6	119.0
Less: Property and other taxes	78.3	70.6	22.2	20.6	100.5	91.2
Less: Depreciation and depletion	111.0	104.9	22.8	19.9	133.8	124.8
Gross Margin	**211.0**	**195.9**	**55.9**	**65.0**	**266.9**	**260.9**
Add back: Operating and maintenance	122.9	91.2	30.7	27.8	153.6	119.0
Add back: Property and other taxes	78.3	70.6	22.2	20.6	100.5	91.2
Add back: Depreciation and depletion	111.0	104.9	22.8	19.9	133.8	124.8
Utility Margin(1)	**$ 523.2**	**$ 462.6**	**$ 131.6**	**$ 133.3**	**$ 654.8**	**$ 595.9**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

	Six Months Ended June 30,			
	2026	2025	Change	% Change
	(dollars in millions)			
Utility Margin				
Electric	$ 523.2	$ 462.6	$ 60.6	13.1 %
Natural Gas	131.6	133.3	(1.7)	(1.3)
Total Utility Margin(1)	**$ 654.8**	**$ 595.9**	**$ 58.9**	**9.9 %**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated utility margin for the six months ended June 30, 2026 was $654.8 million as compared with $595.9 million for the same period in 2025, an increase of $58.9 million, or 9.9 percent. Primary components of the change in utility margin include the following (in millions):

Utility Margin Items Impacting Net Income		Utility Margin 2026 vs. 2025
Base rates	$	37.5
Electric margin from the acquisition of the Puget Interests		10.2
Electric transmission revenue		5.4
Non-recoverable Montana electric supply costs		2.8
Electric retail volumes		(4.9)
Montana property tax tracker collections		(3.5)
Natural gas retail volumes (including a $5.2 million increase due to acquisition of Energy West Operations)		(2.7)
Natural gas production step down		(1.1)
Other		2.9
Change in Utility Margin Items Impacting Net Income		**46.6**
Utility Margin Items Offset Within Net Income		
Property and other taxes recovered in revenue, offset in property and other taxes		5.1
Production tax credits, offset in income tax expense		4.0
Operating expenses recovered in revenue, offset in operating and maintenance expense		3.2
Change in Utility Margin Items Offset Within Net Income		**12.3**
Increase in Consolidated Utility Margin(1)	**$**	**58.9**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Electric retail volumes were impacted by unfavorable weather in all jurisdictions partly offset by customer growth in all jurisdictions. Natural gas retail volumes were impacted by unfavorable weather in all jurisdictions, partly offset by customer growth in all jurisdictions and the acquisition of the Energy West operations in July 2025.

Effective February 1, 2026 the cost sharing mechanism of the PCCAM was suspended on an interim basis pending further review by the MPSC. For the six months ended June 30, 2026, we recorded a decrease in pre-tax earnings of $0.7 million (10 percent of the PCCAM Base cost variance). For the six months ended June 30, 2025, we recorded a decrease in pre-tax earnings of $3.5 million (10 percent of the PCCAM Base cost variance).

	Six Months Ended June 30,			
	2026	2025	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 153.6	$ 119.0	$ 34.6	29.1 %
Administrative and general	88.5	75.1	13.4	17.8
Property and other taxes	100.5	91.4	9.1	10.0
Depreciation and depletion	133.8	124.8	9.0	7.2
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 476.4**	**$ 410.3**	**$ 66.1**	**16.1 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $476.4 million for the six months ended June 30, 2026, as compared with $410.3 million for the six months ended June 30, 2025. Primary components of the change include the following (in millions):

		Operating Expenses 2026 vs. 2025
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income		
Electric generation maintenance (including $12.7 million and $7.6 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)		19.1
Depreciation expense due to plant additions and higher depreciation rates	$	9.0
Merger-related costs, including consulting and legal fees		6.7
Labor and benefits[1]		5.2
Wildfire mitigation expense, partly offset by higher base revenues		4.5
Property and other taxes not recoverable within trackers		4.0
Insurance expense		1.0
Technology implementation and maintenance expenses		1.0
Uncollectible accounts		0.7
Other		5.3
Change in Items Impacting Net Income		**56.5**
Operating Expenses Offset Within Net Income		
Property and other taxes recovered in trackers, offset in revenue		5.1
Operating and maintenance expenses recovered in trackers, offset in revenue		3.2
Deferred compensation, offset in other income		2.0
Pension and other postretirement benefits, offset in other income[1]		(0.7)
Change in Items Offset Within Net Income		**9.6**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$**	**66.1**

(1) In order to present the total change in labor and benefits, we have included the change in the non-service cost component of our pension and other postretirement benefits, which is recorded within other income on our Condensed Consolidated Statements of Income. This change is offset within this table as it does not affect our operating expenses.

Consolidated operating income for the six months ended June 30, 2026 was $178.4 million as compared with $185.5 million in the same period of 2025. This decrease was primarily due to retail volumes, Montana property tax collections, operating, administrative, and general costs, including merger-related costs and costs associated with our additional ownership interests in Colstrip Units 3 and 4, and depreciation expense. These were offset in part by new rates, lower non-recoverable Montana electric supply costs, and transmission revenues.

Consolidated interest expense was $80.2 million for the six months ended June 30, 2026 as compared with $72.8 million for the same period of 2025. This increase was due to higher borrowings and interest rates partly offset by higher capitalization of AFUDC.

Consolidated other income was $7.6 million for the six months ended June 30, 2026 as compared to $4.0 million during the same period of 2025. This increase was primarily due to an increase in the value of deferred shares held in trust for deferred compensation, a prior year $1.0 million expense accrual related to an estimated penalty for the previously disclosed CREP informed by a MPSC ruling, and higher capitalization of AFUDC, partly offset by higher non-service component pension expense.

Consolidated income tax expense for the six months ended June 30, 2026 was $17.3 million as compared to $18.6 million in the same period of 2025. Our effective tax rate for the six months ended June 30, 2026 was 16.3% as compared with 15.9% for the same period in 2025.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

	Six Months Ended June 30,			
	2026		2025	
	(in dollars)	(in percent)	(in dollars)	(in percent)
Income before income taxes	$ 105.7		$ 116.8	
Income tax calculated at federal statutory rate	22.2	21.0 %	24.5	21.0 %
State income tax, net of federal provision	1.4	1.3	0.9	0.8
Tax Credits				
Production tax credits	(1.1)	(1.0)	(2.7)	(2.3)
Other	—	—	0.5	0.4
Impact of utility ratemaking on income taxes				
Flow-through repairs deductions	(12.0)	(11.4)	(10.8)	(9.2)
Amortization of excess deferred income taxes	(1.9)	(1.8)	(0.8)	(0.7)
AFUDC, net	(0.8)	(0.8)	(0.8)	(0.7)
Plant and depreciation of flow through items	9.1	8.6	6.8	5.8
Changes in Unrecognized Tax Benefits				
Interest and penalties	—	—	0.6	0.5
Nontaxable and nondeductible items	0.4	0.4	0.2	0.2
Other	0.0	0.0	0.2	0.1
	(4.9)	(4.7)	(5.9)	(5.1)
Income Tax Expense and Effective Tax Rate	$ 17.3	16.3 %	$ 18.6	15.9 %

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

ELECTRIC SEGMENT

We have various classifications of electric revenues, defined as follows:

- Retail: Sales of electricity to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- Regulatory amortization: Primarily represents timing differences for electric supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in fuel, purchased supply and direct transmission expense and therefore has minimal impact on utility margin. The amortization of these amounts are offset in retail revenue.
- Transmission: Reflects transmission revenues regulated by the FERC.
- Wholesale and other: Primarily represents revenues from wholesale electricity sales, as well as other miscellaneous electric revenues.

Three Months Ended June 30, 2026 Compared with the Three Months Ended June 30, 2025

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 98,447	$ 81,824	$ 16,623	20.3 %	594	571	337,611	333,302
South Dakota	17,983	16,235	1,748	10.8	121	113	51,990	51,663
Residential	**116,430**	**98,059**	**18,371**	**18.7**	**715**	**684**	**389,601**	**384,965**
Montana	110,833	93,910	16,923	18.0	761	754	77,961	77,173
South Dakota	30,341	27,737	2,604	9.4	252	246	13,274	13,182
Commercial	**141,174**	**121,647**	**19,527**	**16.1**	**1,013**	**1,000**	**91,235**	**90,355**
Industrial	10,831	9,888	943	9.5	667	684	81	80
Other	14,144	9,421	4,723	50.1	53	42	28,770	28,761
Total Retail Electric	**$ 282,579**	**$ 239,015**	**$ 43,564**	**18.2 %**	**2,448**	**2,410**	**509,687**	**504,161**
Regulatory amortization	(3,645)	10,325	(13,970)	(135.3)				
Transmission	29,141	28,147	994	3.5				
Wholesale and Other	16,179	1,981	14,198	716.7				
Total Revenues	**$ 324,254**	**$ 279,468**	**$ 44,786**	**16.0 %**				
Fuel, purchased supply and direct transmission expense(1)	**72,836**	**59,603**	**13,233**	**22.2**				
Utility Margin(2)	**$ 251,418**	**$ 219,865**	**$ 31,553**	**14.4 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Cooling Degree Days			2026 as compared with:	
	2026	2025	Historic Average	2025	Historic Average
Montana	34	55	59	38% cooler	42% cooler
South Dakota	137	99	69	38% warmer	99% warmer
	Heating Degree Days			**2026 as compared with:**	
	2026	**2025**	**Historic Average**	**2025**	**Historic Average**
Montana(1)	1,147	1,033	1,128	11% colder	2% colder
South Dakota	1,344	1,223	1,486	10% colder	10% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in electric utility margin for the three months ended June 30, 2026 and 2025 (in millions):

		Utility Margin 2026 vs. 2025
Utility Margin Items Impacting Net Income		
Base rates	$	13.8
Retail volumes		7.3
Electric margin from the acquisition of the Colstrip Puget Interests		4.7
Electric transmission revenue		1.0
Non-recoverable Montana electric supply costs		0.8
Montana property tax tracker collections		(0.6)
Other		0.5
Change in Utility Margin Items Impacting Net Income		27.5
Utility Margin Items Offset Within Net Income		
Operating expenses recovered in revenue, offset in operating and maintenance expense		2.5
Production tax credits, offset in income tax expense		1.4
Property and other taxes recovered in revenue, offset in property and other taxes		0.2
Change in Utility Margin Items Offset Within Net Income		4.1
Increase in Utility Margin(1)	**$**	**31.6**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Electric retail volumes were impacted by favorable weather in South Dakota and customer growth in all jurisdictions, partly offset by unfavorable weather in Montana.

Effective February 1, 2026 the cost sharing mechanism of the PCCAM was suspended on an interim basis pending further review by the MPSC. For the three months ended June 30, 2025, we recorded a decrease in pre-tax earnings of $0.8 million (10 percent of the PCCAM Base cost variance).

The change in regulatory amortization revenue is primarily due to timing differences between when we incur electric supply costs and property taxes and when we recover these costs in rates from our customers, which has a minimal impact on utility margin. Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

Six Months Ended June 30, 2026 Compared with the Six Months Ended June 30, 2025

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 218,885	$ 196,801	$ 22,084	11.2 %	1,377	1,473	337,395	332,820
South Dakota	41,212	38,527	2,685	7.0	299	308	52,005	51,727
Residential	**260,097**	**235,328**	**24,769**	**10.5**	**1,676**	**1,781**	**389,400**	**384,547**
Montana	217,315	190,862	26,453	13.9	1,550	1,600	78,190	77,296
South Dakota	61,738	57,051	4,687	8.2	521	530	13,256	13,156
Commercial	**279,053**	**247,913**	**31,140**	**12.6**	**2,071**	**2,130**	**91,446**	**90,452**
Industrial	22,695	19,988	2,707	13.5	1,369	1,388	81	80
Other	19,653	14,114	5,539	39.2	65	54	27,804	27,895
Total Retail Electric	**$ 581,498**	**$ 517,343**	**$ 64,155**	**12.4 %**	**5,181**	**5,353**	**508,731**	**502,974**
Regulatory amortization	6,426	38,015	(31,589)	(83.1)				
Transmission	60,112	54,703	5,409	9.9				
Wholesale and Other	38,272	4,890	33,382	682.7				
Total Revenues	**$ 686,308**	**$ 614,951**	**$ 71,357**	**11.6 %**				
Fuel, purchased supply and direct transmission expense(1)	**163,111**	**152,355**	**10,756**	**7.1**				
Utility Margin(2)	**$ 523,197**	**$ 462,596**	**$ 60,601**	**13.1 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Cooling Degree Days			2026 as compared with:	
	2026	2025	Historic Average	2025	Historic Average
Montana	34	55	59	38% cooler	42% cooler
South Dakota	137	99	69	38% warmer	99% warmer

	Heating Degree Days			2026 as compared with:	
	2026	2025	Historic Average	2025	Historic Average
Montana(1)	3,752	4,553	4,523	18% warmer	17% warmer
South Dakota	4,906	5,230	5,601	6% warmer	12% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in electric utility margin for the six months ended June 30, 2026 and 2025 (in millions):

		Utility Margin 2026 vs. 2025
Utility Margin Items Impacting Net Income		
Base rates	$	37.5
Electric margin from the acquisition of the Puget Interests		10.2
Electric transmission revenue		5.4
Non-recoverable Montana electric supply costs		2.8
Retail volumes		(4.9)
Montana property tax tracker collections		(3.0)
Other		1.5
Change in Utility Margin Items Impacting Net Income		49.5
Utility Margin Items Offset Within Net Income		
Production tax credits, offset in income tax expense		4.0
Property and other taxes recovered in revenue, offset in property and other taxes		3.9
Operating expenses recovered in revenue, offset in operating and maintenance expense		3.2
Change in Utility Margin Items Offset Within Net Income		11.1
Increase in Utility Margin(1)	**$**	**60.6**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Electric retail volumes were impacted by unfavorable weather in all jurisdictions partly offset by customer growth in all jurisdictions.

Effective February 1, 2026 the cost sharing mechanism of the PCCAM was suspended on an interim basis pending further review by the MPSC. For the six months ended June 30, 2026, we recorded a decrease in pre-tax earnings of $0.7 million (10 percent of the PCCAM Base cost variance). For the six months ended June 30, 2025, we recorded a decrease in pre-tax earnings of $3.5 million (10 percent of the PCCAM Base cost variance).

The change in regulatory amortization revenue is due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers, which has a minimal impact on utility margin. Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

NATURAL GAS SEGMENT

We have various classifications of natural gas revenues, defined as follows:

- Retail: Sales of natural gas to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- Regulatory amortization: Primarily represents timing differences for natural gas supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in fuel, purchased supply and direct transmission expenses and therefore has minimal impact on utility margin. The amortization of these amounts are offset in retail revenue.
- Wholesale: Primarily represents transportation and storage for others.

Three Months Ended June 30, 2026 Compared with the Three Months Ended June 30, 2025

	Revenues		Change		Dekatherms (Dkt)		Avg. Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 19,711	$ 17,968	$ 1,743	9.7 %	2,399	1,949	218,062	187,134
South Dakota	5,776	5,566	210	3.8	576	524	43,202	42,821
Nebraska	4,196	4,523	(327)	(7.2)	371	391	37,963	37,907
Residential	**29,683**	**28,057**	**1,626**	**5.8**	**3,346**	**2,864**	**299,227**	**267,862**
Montana	12,211	10,499	1,712	16.3	1,548	1,181	30,582	26,613
South Dakota	4,141	3,920	221	5.6	674	593	7,713	7,549
Nebraska	1,994	2,346	(352)	(15.0)	272	308	5,162	5,098
Commercial	**18,346**	**16,765**	**1,581**	**9.4**	**2,494**	**2,082**	**43,457**	**39,260**
Industrial	844	144	700	486.1	967	17	247	239
Other	268	270	(2)	(0.7)	42	38	250	207
Total Retail Gas	**$ 49,141**	**$ 45,236**	**$ 3,905**	**8.6 %**	**6,849**	**5,001**	**343,181**	**307,568**
Regulatory amortization	5,925	5,189	736	14.2				
Transportation, wholesale and other	13,279	12,820	459	3.6				
Total Revenues	**$ 68,345**	**$ 63,245**	**$ 5,100**	**8.1 %**				
Fuel, purchased supply and direct transmission expense(1)	**16,987**	**15,668**	**1,319**	**8.4**				
Utility Margin(2)	**$ 51,358**	**$ 47,577**	**$ 3,781**	**7.9 %**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Heating Degree Days			2026 as compared with:	
	2026	2025	Historic Average	2025	Historic Average
Montana(1)	1,201	1,093	1,175	10% colder	2% colder
South Dakota	1,344	1,223	1,486	10% colder	10% warmer
Nebraska	871	959	1,134	9% warmer	23% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in natural gas utility margin for the three months ended June 30, 2026 and 2025:

	Utility Margin 2026 vs. 2025 (in millions)
Utility Margin Items Impacting Net Income	
Retail volumes (including a $2.0 million increase due to acquisition of Energy West Operations)	$ 3.5
Montana property tax tracker collections	0.4
Natural gas production step down	(0.4)
Other	0.6
Change in Utility Margin Items Impacting Net Income	4.1
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property and other taxes	(0.2)
Operating expenses recovered in revenue, offset in operating and maintenance expense	(0.1)
Change in Utility Margin Items Offset Within Net Income	(0.3)
Increase in Utility Margin(1)	**$ 3.8**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Natural gas retail volumes were impacted by favorable weather in Montana and South Dakota, the acquisition of the Energy West operations in July 2025, and customer growth, partly offset by unfavorable weather in Nebraska.

Six Months Ended June 30, 2026 Compared with the Six Months Ended June 30, 2025

	Revenues		Change		Dekatherms (Dkt)		Avg. Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 67,849	$ 69,386	$ (1,537)	(2.2)%	8,591	8,466	218,022	187,066
South Dakota	20,300	21,136	(836)	(4.0)	2,167	2,311	43,305	42,941
Nebraska	15,357	17,732	(2,375)	(13.4)	1,492	1,773	38,070	38,023
Residential	**103,506**	**108,254**	**(4,748)**	**(4.4)**	**12,250**	**12,550**	**299,397**	**268,030**
Montana	39,088	37,257	1,831	4.9	5,368	4,813	30,568	26,588
South Dakota	15,895	15,095	800	5.3	2,222	2,203	7,741	7,545
Nebraska	8,500	9,787	(1,287)	(13.2)	1,044	1,254	5,182	5,122
Commercial	**63,483**	**62,139**	**1,344**	**2.2**	**8,634**	**8,270**	**43,491**	**39,255**
Industrial	1,635	628	1,007	160.4	1,772	86	246	238
Other	792	861	(69)	(8.0)	125	132	243	207
Total Retail Gas	**$ 169,416**	**$ 171,882**	**$ (2,466)**	**(1.4)%**	**22,781**	**21,038**	**343,377**	**307,730**
Regulatory amortization	4,924	(4,247)	9,171	215.9				
Transportation, wholesale and other	29,521	26,757	2,764	10.3				
Total Revenues	**$ 203,861**	**$ 194,392**	**$ 9,469**	**4.9 %**				
Fuel, purchased supply and direct transmission expense[1]	**72,277**	**61,113**	**11,164**	**18.3**				
Utility Margin[2]	**$ 131,584**	**$ 133,279**	**$ (1,695)**	**(1.3)%**				

(1) Exclusive of depreciation and depletion.
(2) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Heating Degree Days			2026 as compared with:	
	2026	2025	Historic Average	2025	Historic Average
Montana[1]	3,923	4,590	4,598	15% warmer	15% warmer
South Dakota	4,906	5,230	5,601	6% warmer	12% warmer
Nebraska	3,634	4,368	4,426	17% warmer	18% warmer

(1) Montana electric and natural gas heating degree days may differ due to differences in service territory.

The following summarizes the components of the changes in natural gas utility margin for the six months ended June 30, 2026 and 2025:

	Utility Margin 2026 vs. 2025 (in millions)
Utility Margin Items Impacting Net Income	
Retail volumes (including a $5.2 million increase due to acquisition of Energy West Operations)	$ (2.7)
Natural gas production step down	(1.1)
Montana property tax tracker collections	(0.5)
Other	1.4
Change in Utility Margin Items Impacting Net Income	(2.9)
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property tax expense	1.2
Change in Utility Margin Items Offset Within Net Income	1.2
Decrease in Utility Margin(1)	**$ (1.7)**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

Natural gas retail volumes were impacted by unfavorable weather in all jurisdictions, partly offset by customer growth in all jurisdictions and the acquisition of the Energy West operations in July 2025.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. For NorthWestern Energy Group, liquidity is primarily provided through its revolving credit facility and dividends from its utility operating subsidiaries, NW Corp and NWE Public Service. These subsidiaries are subject to certain restrictions that may limit the amount of their dividend distributions. See Note 18 - Common Stock in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025 for further information regarding these dividend restrictions. As of June 30, 2026, we are in compliance with these provisions.

We believe our cash flows from operations, existing borrowing capacity, debt and equity issuances and future utility rate increases should be sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures. We plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases, and expect to continue targeting a long-term dividend payout ratio of 60 - 70 percent of earnings per share; however, there can be no assurance that we will be able to meet these targets.

As of June 30, 2026, our total net liquidity was approximately $339.2 million, including $4.2 million of cash and cash equivalents and $335.0 million of revolving credit facility availability with no letters of credit outstanding.

Cash Flows

The following table summarizes our consolidated cash flows (in millions):

	Six Months Ended June 30,	
	2026	2025
Operating Activities		
Net income	$ 88.5	$ 98.2
Adjustments to reconcile net income to cash provided by operations	149.6	144.1
Changes in working capital	12.4	(22.1)
Other noncurrent assets and liabilities	(17.3)	(8.6)
Cash Provided by Operating Activities	**233.2**	**211.6**
Investing Activities		
Property, plant and equipment additions	(304.8)	(221.0)
Investment in debt & equity securities	(1.0)	(5.8)
Cash Used in Investing Activities	**(305.8)**	**(226.8)**
Financing Activities		
Issuance of long-term debt	375.0	500.0
Line of credit repayments, net	(114.0)	(103.0)
Dividends on common stock	(82.1)	(80.7)
Repayments on long-term debt	(60.0)	(300.0)
Repayment of short-term borrowings	(50.0)	—
Other financing activities, net	(1.9)	(3.6)
Cash Provided by Financing Activities	**67.0**	**12.7**
Decrease in Cash, Cash Equivalents, and Restricted Cash	**(5.6)**	**(2.5)**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	30.7	29.0
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 25.1**	**$ 26.5**

Operating Activities

As of June 30, 2026, cash, cash equivalents, and restricted cash were $25.1 million as compared with $30.7 million as of December 31, 2025 and $26.5 million as of June 30, 2025. Cash provided by operating activities totaled $233.2 million for the six months ended June 30, 2026 as compared with $211.6 million during the six months ended June 30, 2025. The changes in cash flows from operating activities generally follow the results of operations, as discussed above in the consolidated results of operations for the six months ended June 30, 2026, and are affected by changes in working capital. The increase in cash provided by working capital is primarily due to a decrease in our net cash outflows for energy supply costs, as shown in the table below.

Uncollected energy supply costs (in millions)

	Beginning of period	End of period	Net cash outflows
2025	$ 5.9	$ 28.6	$ (22.7)
2026	$ 44.8	$ 51.9	$ (7.1)
		Decrease in net cash outflows	$ 15.6

Investing Activities

Cash used in investing activities totaled $305.8 million during the six months ended June 30, 2026, as compared with $226.8 million during the six months ended June 30, 2025. Plant additions during the first six months of 2026 include maintenance additions of approximately $218.7 million and capacity related capital expenditures of $86.1 million. Plant additions during the first six months of 2025 included maintenance additions of approximately $149.4 million and capacity related capital expenditures of approximately $71.6 million.

Financing Activities

Cash provided by financing activities totaled $67.0 million during the six months ended June 30, 2026, as compared with $12.7 million during the six months ended June 30, 2025. During the six months ended June 30, 2026, cash provided by financing activities reflects proceeds from the issuance of debt of $375.0 million, partly offset by net repayments under our revolving lines of credit of $114.0 million, payment of dividends of $82.1 million, repayment of $60.0 million of South Dakota First Mortgage bonds, and repayment of $50.0 million of the NWE Group Term Loan. During the six months ended June 30, 2025, cash provided by financing activities reflects proceeds from the issuance of long-term debt of $500.0 million, partly offset by repayment of $300.0 million of Montana and South Dakota First Mortgage bonds, net repayments under our revolving lines of credit of $103.0 million and payment of dividends of $80.7 million.

Cash Requirements and Capital Resources

We believe our cash flows from operations, existing borrowing capacity, debt and equity issuances and future rate increases should be sufficient to satisfy our material cash requirements over the short-term and the long-term. As a rate-regulated utility our customer rates are generally structured to recover expected operating costs, with an opportunity to earn a return on our invested capital. This structure supports recovery for many of our operating expenses, although there are situations where the timing of our cash outlays results in increased working capital requirements. Due to the seasonality of our utility business, our short-term working capital requirements typically peak during the coldest winter months and warmest summer months when we cover the lag between when purchasing energy supplies and when customers pay for these costs. Our credit facilities may also be utilized for funding cash requirements during seasonally active construction periods, with peak activity during warmer months. Our cash requirements also include a variety of contractual obligations as outlined below in the "Contractual Obligations and Other Commitments" section.

Our material cash requirements are also related to investment in our business through our capital expenditure program. Our estimated capital expenditures are discussed in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025 within the Management's Discussion and Analysis of Financial Condition and Results of Operations under the "Significant Infrastructure Investments and Initiatives" section. As of June 30, 2026, there have been no material changes in our estimated capital expenditures. The actual amount of capital expenditures is subject to certain factors including the impact that a material change in operations, available financing, supply chain issues, or inflation could impact our current liquidity and ability to fund capital resource requirements. Events such as these could cause us to defer a portion of our planned capital expenditures, as necessary. To fund our strategic growth opportunities, we evaluate the additional capital need in balance with debt capacity and equity issuances that would be intended to allow us to maintain investment grade ratings.

Short-term Borrowings

For information on our recent short-term borrowings activity, see Note 6 - Financing Activities to the Condensed Consolidated Financial Statements included herein. For further information on our short-term borrowings, see Note 12 - Short-Term Borrowings and Credit Arrangements in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025.

Credit Facilities

Liquidity is generally provided by internal operating cash flows and the use of our unsecured revolving credit facilities. We utilize availability under our revolving credit facilities to manage our cash flows due to the seasonality of our business and to fund capital investment. Cash on hand in excess of current operating requirements is generally used to invest in our business and reduce borrowings.

For further information on our credit facilities, see Note 12 - Short-Term Borrowings and Credit Arrangements in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025.

As of June 30, 2026 and 2025, the outstanding balances of our credit facilities were $290.0 million and $310.0 million, respectively. As of July 24, 2026, the availability under our credit facilities was approximately $316.0 million, and there were no letters of credit outstanding.

Long-term Debt and Equity

We generally issue long-term debt to refinance other long-term debt maturities and borrowings under our revolving credit facilities, as well as to fund long-term capital investments and strategic opportunities.

For further information on our recent long-term debt activity, See Note 6 - Financing Activities to the Condensed Consolidated Financial Statements included herein.

We generally issue equity securities to fund long-term investment in our business. We evaluate our equity issuance needs to support our plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases.

Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of July 24, 2026, our current ratings with these agencies are as follows:

	Issuer Rating	Senior Secured Rating	Senior Unsecured Rating	Outlook
NorthWestern Energy Group				
Fitch[(1)]	BBB	-	BBB	Stable
Moody's	-	-	-	-
S&P	BBB	-	-	Positive
NW Corp				
Fitch[(1)]	BBB	A-	BBB+	Stable
Moody's	Baa2	A3	Baa2	Stable
S&P	BBB	A-	-	Positive
NWE Public Service				
Fitch[(1)]	BBB	A-	BBB+	Stable
Moody's	Baa2	A3	-	Stable
S&P	BBB	A-	-	Stable

(1) This Fitch Issuer Rating represents the Issuer Default Rating.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. The following table summarizes our contractual cash obligations and commitments as of June 30, 2026.

	Total	2026	2027	2028	2029	2030	Thereafter
				(in thousands)			
Long-term debt[1]	$ 3,499,660	$ 45,000	$ 225,000	$ 469,660	$ 33,000	$ 650,000	$ 2,077,000
Finance leases	9,436	854	1,750	1,838	1,930	2,026	1,038
Short-term borrowings	100,000	100,000	—	—	—	—	—
Estimated pension and other postretirement obligations[2]	45,620	7,196	10,206	9,806	9,306	9,106	N/A
Qualifying facilities liability[3]	140,896	27,697	56,665	56,534	—	—	—
Supply and capacity contracts[4]	3,693,058	216,836	368,342	344,818	344,536	315,957	2,102,569
Contractual interest payments on debt[5]	1,597,493	83,364	160,957	149,578	128,449	114,980	960,165
Commitments for significant capital projects[6]	112,226	103,936	7,572	718	—	—	—
Total Commitments[7]	$ 9,198,389	$ 584,883	$ 830,492	$ 1,032,952	$ 517,221	$ 1,092,069	$ 5,140,772

(1) Represents cash payments for long-term debt and excludes $12.5 million of debt discounts and debt issuance costs, net.
(2) We estimate cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. Pension and postretirement benefit estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(3) One QF requires us to purchase minimum amounts of energy at a price of $130 per MWH through 2028. Our estimated gross contractual obligation related to this QF is approximately $140.9 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $129.7 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. The energy supply costs incurred under these contracts are generally recoverable through rate mechanisms approved by the MPSC.
(5) Contractual interest payments include our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 4.99 percent on the outstanding balance through maturity of the facilities.
(6) Represents significant firm purchase commitments for construction of planned capital projects.
(7) The table above excludes potential tax payments related to uncertain tax benefits as they are not practicable to estimate. Additionally, the table above excludes reserves for environmental remediation and asset retirement obligations as the amount and timing of cash payments may be uncertain.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of financial condition and results of operations is based on our Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances.

We continually evaluate the appropriateness of our estimates and assumptions. Actual results could differ from those estimates. We consider an estimate to be critical if it is material to the Financial Statements and it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate are reasonably likely to occur from period to period. This includes the accounting for the following: regulatory assets and liabilities, pension and postretirement benefit plans and income taxes. These policies were disclosed in Management's Discussion and Analysis of Financial Condition and Results of Operations in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025. As of June 30, 2026, there have been no material changes in these policies.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and counterparty credit exposure. We have established comprehensive risk management policies and procedures to manage these market risks. There have been no material changes in our market risks as disclosed in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms, and accumulated and reported to management, including the principal executive officer and principal financial officer to allow timely decisions regarding required disclosure.

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See Note 11 - Commitments and Contingencies, to the Financial Statements for information regarding legal proceedings.

ITEM 1A. RISK FACTORS

Refer to the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2025 for disclosure of the risk factors that could have a significant impact on our business, financial condition, results of operations or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not changed materially since such disclosure.

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Plans

During the three months ended June 30, 2026, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading agreement" or "non-Rule 10b5-1 trading agreement," as each term is defined in Item 408(a) of Regulation S-K.

ITEM 6. EXHIBITS -

(a) Exhibits

Exhibit 4.1 — Twenty-third Supplemental Indenture, dated as of June 1, 2026, between NorthWestern Energy Public Service Corporation and The Bank of New York Mellon, as trustee. (incorporated by reference to Exhibit 4.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated June 15, 2026, Commission File No. 000-56598).

Exhibit 4.2 — Forty-eighth Supplemental Indenture, dated as of May 1, 2026, between NorthWestern Corporation and The Bank of New York Mellon and Dimple Gandhi, as trustees. (incorporated by reference to Exhibit 4.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated May 27, 2026, Commission File No. 000-56598).

Exhibit 10.1 — Secured Term Loan Credit Agreement (incorporated by reference to Exhibit 10.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated May 27, 2026, Commission File No. 000-56598).

Exhibit 31.1 — Certification of chief executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 - NorthWestern Energy Group, Inc.

Exhibit 31.2 — Certification of chief financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 - NorthWestern Energy Group, Inc.

Exhibit 32.1 — Certification of chief executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - NorthWestern Energy Group, Inc.

Exhibit 32.2 — Certification of chief financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - NorthWestern Energy Group, Inc.

Exhibit 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.

Exhibit 101.SCH—Inline XBRL Taxonomy Extension Schema Document

Exhibit 101.CAL—Inline XBRL Taxonomy Extension Calculation Linkbase Document

Exhibit 101.DEF—Inline XBRL Taxonomy Extension Definition Linkbase Document

Exhibit 101.LAB—Inline XBRL Taxonomy Label Linkbase Document

Exhibit 101.PRE—Inline XBRL Taxonomy Extension Presentation Linkbase Document

Exhibit 104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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.

NorthWestern Energy Group, Inc.

Date: July 30, 2026

By: /s/ CRYSTAL LAIL

Crystal Lail

Vice President and Chief Financial Officer

Duly Authorized Officer and Principal Financial Officer