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, 2025

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

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, 61,393,380 shares outstanding at July 25, 2025

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 and changes in customer usage patterns and preferences 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:

- adverse determinations by regulators, such as adverse outcomes from the denial of interim rates or final rates not consistent with a reasonable ability to earn our allowed returns, 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;
- 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, recent high levels of inflation for product, 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.

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,	
	2025	2024	2025	2024
Revenues				
Electric	$ 279,468	$ 260,134	$ 614,951	$ 603,320
Gas	63,245	59,795	194,392	191,951
Total Revenues	342,713	319,929	809,343	795,271
Operating expenses				
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	75,271	76,480	213,468	251,201
Operating and maintenance	62,336	57,367	119,045	111,549
Administrative and general	33,773	31,281	75,130	71,726
Property and other taxes	48,168	36,256	91,408	83,427
Depreciation and depletion	62,379	56,933	124,779	113,676
Total Operating Expenses	281,927	258,317	623,830	631,579
Operating income	60,786	61,612	185,513	163,692
Interest expense, net	(36,254)	(31,875)	(72,765)	(62,854)
Other income, net	78	6,160	4,006	10,479
Income before income taxes	24,610	35,897	116,754	111,317
Income tax expense	(3,382)	(4,243)	(18,586)	(14,577)
Net Income	$ 21,228	$ 31,654	$ 98,168	$ 96,740
Average Common Shares Outstanding	61,381	61,289	61,360	61,277
Basic Earnings per Average Common Share	$ 0.35	$ 0.52	$ 1.60	$ 1.58
Diluted Earnings per Average Common Share	$ 0.35	$ 0.52	$ 1.60	$ 1.58
Dividends Declared per Common Share	$ 0.66	$ 0.65	$ 1.32	$ 1.30

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,	
	2025	**2024**	**2025**	**2024**
Net Income	$ 21,228	$ 31,654	$ 98,168	$ 96,740
Other comprehensive income, net of tax:				
Foreign currency translation adjustment	4	(1)	5	(2)
Reclassification of net losses on derivative instruments	113	113	226	226
Total Other Comprehensive Income	117	112	231	224
Comprehensive Income	$ 21,345	$ 31,766	$ 98,399	$ 96,964

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands, except share data)

	June 30, 2025	December 31, 2024
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,936	$ 4,283
Restricted cash	23,612	24,734
Accounts receivable, net	154,923	187,764
Inventories	125,398	122,940
Regulatory assets	67,504	39,851
Prepaid expenses and other	28,707	38,614
Total current assets	**403,080**	**418,186**
Property, plant, and equipment, net	6,531,509	6,398,275
Goodwill	357,586	357,586
Regulatory assets	778,974	764,414
Other noncurrent assets	64,818	59,063
Total Assets	**$ 8,135,967**	**$ 7,997,524**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 3,731	$ 3,596
Current portion of long-term debt	59,964	299,950
Short-term borrowings	100,000	100,000
Accounts payable	93,744	111,794
Accrued expenses and other	251,932	254,599
Regulatory liabilities	28,061	32,261
Total current liabilities	**537,432**	**802,200**
Long-term finance leases	0	1,865
Long-term debt	3,029,611	2,695,343
Deferred income taxes	702,905	663,430
Noncurrent regulatory liabilities	674,431	660,942
Other noncurrent liabilities	311,912	316,044
Total Liabilities	**5,256,291**	**5,139,824**
Commitments and Contingencies (Note 11)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 64,875,751 and 61,387,122 shares, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	649	648
Treasury stock at cost	(97,705)	(97,394)
Paid-in capital	2,088,674	2,084,133
Retained earnings	894,531	877,017
Accumulated other comprehensive loss	(6,473)	(6,704)
Total Shareholders' Equity	**2,879,676**	**2,857,700**
Total Liabilities and Shareholders' Equity	**$ 8,135,967**	**$ 7,997,524**

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(in thousands)

	Six Months Ended June 30,	
	2025	**2024**
OPERATING ACTIVITIES:		
Net income	$ 98,168	$ 96,740
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and depletion	124,779	113,676
Amortization of debt issuance costs, discount and deferred hedge gain	2,343	2,337
Stock-based compensation costs	4,168	3,797
Equity portion of allowance for funds used during construction	(4,066)	(9,397)
Loss on disposition of assets	151	21
Impairment of alternative energy storage investment	—	4,659
Deferred income taxes	16,746	12,953
Changes in current assets and liabilities:		
Accounts receivable	32,841	62,757
Inventories	(2,458)	(417)
Other current assets	9,907	(1,130)
Accounts payable	(27,688)	(20,693)
Accrued expenses and other	(2,861)	(2,157)
Regulatory assets	(27,653)	(12,398)
Regulatory liabilities	(4,200)	(24,939)
Other noncurrent assets and liabilities	(8,576)	(1,866)
Cash Provided by Operating Activities	**211,601**	**223,943**
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(220,978)	(247,361)
Investment in debt & equity securities	(5,778)	(917)
Cash Used in Investing Activities	**(226,756)**	**(248,278)**
FINANCING ACTIVITIES:		
Dividends on common stock	(80,654)	(79,275)
Issuance of long-term debt	500,000	215,000
Issuance of short-term borrowings	—	100,000
Repayments on long-term debt	(300,000)	(100,000)
Line of credit repayments, net	(103,000)	(105,000)
Other financing activities, net	(3,660)	(539)
Cash Provided by Financing Activities	**12,686**	**30,186**
(Decrease) Increase in Cash, Cash Equivalents, and Restricted Cash	(2,469)	5,851
Cash, Cash Equivalents, and Restricted Cash, beginning of period	29,017	25,187
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 26,548**	**$ 31,038**
Supplemental Cash Flow Information:		
Cash (received) paid during the period for:		
Production tax credits(1)	(8,255)	—
Interest	67,166	59,995
Significant non-cash transactions:		
Capital expenditures included in accounts payable	32,015	27,144

(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, 2024	**64,798**	**3,515**	**$ 648**	**$ (97,990)**	**$2,080,953**	**$836,951**	**$ (7,544)**	**$ 2,813,018**
Net income	—	—	—	—	—	31,654	—	31,654
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(1)	(1)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	**113**	113
Stock-based compensation	5	—	—	—	1,732	—	—	1,732
Issuance of shares	—	(11)	—	214	172	—	—	386
Dividends on common stock ($0.650 per share)	—	—	—	—	—	(39,645)	—	(39,645)
Balance at June 30, 2024	**64,803**	**3,504**	**$ 648**	**$ (97,776)**	**$2,082,857**	**$828,960**	**$ (7,432)**	**$ 2,807,257**
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**

	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, 2023	**64,762**	**3,513**	**$ 648**	**$ (97,926)**	**$ 2,078,753**	**$ 811,495**	**$ (7,656)**	**$ 2,785,314**
Net income	—	—	—	—	—	96,740	—	96,740
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(2)	(2)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	226	226
Stock-based compensation	41	—	—	(272)	3,771	—	—	3,499
Issuance of shares	—	(9)	—	422	333	—	—	755
Dividends on common stock ($1.300 per share)	—	—	—	—	—	(79,275)	—	(79,275)
Balance at June 30, 2024	**64,803**	**3,504**	**$ 648**	**$ (97,776)**	**$ 2,082,857**	**$ 828,960**	**$ (7,432)**	**$ 2,807,257**
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**

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 842,100 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, 2025 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, 2024.

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, 2025	December 31, 2024	June 30, 2024	December 31, 2023
Cash and cash equivalents	$ 2,936	$ 4,283	$ 6,398	$ 9,164
Restricted cash	23,612	24,734	24,640	16,023
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 26,548	$ 29,017	$ 31,038	$ 25,187

Goodwill

We completed our annual goodwill impairment test as of April 1, 2025, and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(2) Acquisition

In July 2024, NW Corp entered into an Asset Purchase Agreement with Hope Utilities to acquire its Energy West natural gas distribution system and operations serving approximately 33,000 customers located in Great Falls, Cut Bank, and West Yellowstone, Montana. In May 2025, the Montana Public Service Commission (MPSC) approved this acquisition and on July 1, 2025, NW Corp completed this acquisition for approximately $36.5 million in cash, which is subject to certain post-closing working capital adjustments. Determination of the final purchase price and allocation to the acquired assets and assumed liabilities are expected to be completed in the second half of 2025. Upon the completion of the acquisition, NW Corp transferred the utility operations to its two wholly-owned subsidiaries, NorthWestern Great Falls Gas LLC and NorthWestern Cut Bank Gas LLC.

(3) Regulatory Matters

Montana Rate Review

In July 2024, we filed a Montana electric and natural gas rate review with the MPSC. In November 2024, the MPSC partially approved our requested interim rates effective December 1, 2024, subject to refund. Subsequently, we modified our request through rebuttal testimony. In March 2025, we filed a natural gas settlement with certain parties. In April 2025, we filed a partial electric settlement with certain other parties. Both settlements are subject to approval by the MPSC.

The partial electric settlement includes, among other things, agreement on base revenue increases (excluding base revenues associated with Yellowstone County Generating Station (YCGS)), allocated cost of service, rate design, updates to the amount of revenues associated with property taxes (excluding property taxes associated with YCGS), regulatory policy issues related to requested changes in regulatory mechanisms, and agreement to support a separate motion for revised electric interim rates. The partial electric settlement provides for the deferral and annual recovery of incremental operating costs related to wildfire mitigation and insurance expenses through the Wildfire Mitigation Balancing Account.

The natural gas settlement includes, among other things, agreement on base revenues, allocated cost of service, rate design, updates to the amount of revenues associated with property taxes, and agreement to support a separate motion for revised natural gas interim rates.

The details of our filing request, as adjusted in rebuttal testimony, are set forth below:

Requested Revenue Increase (Decrease) Through Rebuttal Testimony (in millions)

	Electric	Natural Gas
Base Rates	$ 153.8	27.9
Power Cost & Credit Adjustment Mechanism (PCCAM)(1)	(94.5)	n/a
Property Tax (tracker base adjustment)(1)	(1.3)	0.1
Total Revenue Increase Requested through Rebuttal Testimony	$ 58.0	$ 28.0

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.

The details of our interim rates granted are set forth below:

Interim Revenue Increase (Decrease) Granted (in millions)

	Electric(1)	Natural Gas(2)
Base Rates	$ 18.4	$ 17.4
PCCAM(3)	(88.0)	n/a
Property Tax (tracker base adjustment)(3)(4)	7.4	0.2
Total Interim Revenue Granted	$ (62.2)	$ 17.6

(1) These electric interim rates were effective December 1, 2024, through May 22, 2025. See further discussion on revised electric interim rates below.
(2) These natural gas interim rates were effective December 1, 2024, and are expected to remain in effect until the MPSC final order rates are effective.
(3) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(4) Our requested interim property tax base increase went into effect on January 1, 2025, as part of our 2024 property tax tracker filing.

The details of our settlement agreement are set forth below:

Requested Revenue Increase (Decrease) through Settlement Agreements (in millions)		
	Electric[1]	Natural Gas
Base Rates:		
Base Rates (Settled)	$ 66.4	$ 18.0
Base Rates - YCGS (Non-settled)[2][3]	43.9	n/a
Requested Base Rates	110.3	18.0
Pass-through items:		
Property Tax (tracker base adjustment) (Settled)[4]	(5.2)	0.1
Property Tax (tracker base adjustment) - YCGS (Non-settled)[2][4]	4.0	n/a
PCCAM (Non-settled)[2][3][4]	(94.5)	n/a
Requested Pass-Through Rates	(95.7)	0.1
Total Requested Revenue Increase	$ 14.6	$ 18.1

(1) We implemented these electric rates on July 2, 2025, on an interim basis, subject to refund.
(2) These items were not included within the partial electric settlement and will be contested items that are expected to be determined in the MPSC's final order.
(3) Intervenor positions on YCGS propose up to an $11.6 million reduction to the base rate revenue request and an additional $38.4 million decrease to the PCCAM base.
(4) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.

On May 23, 2025, as permitted by Montana statute, we implemented our initially requested electric rates, reflecting a base rate revenue increase of $156.5 million, on an interim basis, subject to refund with interest. Within our June 30, 2025 financial statements, we have deferred base rate revenues collected between May 23, 2025, and June 30, 2025, down to our requested revised electric interim rates of $110.3 million as shown within the above table. As of June 30, 2025, we have deferred approximately $3.5 million of base rate revenues collected. On June 20, 2025, we submitted the revised electric interim rates as shown within the above table to the MPSC for approval. The MPSC subsequently approved this request and the revised rates were implemented on July 2, 2025.

As discussed above, if the MPSC chooses to accept the intervenors positions on the remaining contested issues or does not accept the Settlement Agreements in its final order, losses related to excess interim revenues collected will be incurred. Additionally, any difference between interim and final approved rates will be refunded to customers with interest. However, if final approved rates are higher than interim rates, we will not recover the difference.

A hearing on the electric and natural gas rate review was held in June 2025, and final briefs are due in August 2025. Interim rates will remain in effect on a refundable basis, with interest, until the MPSC issues a final order.

Nebraska Natural Gas Rate Review

In June 2024, we filed a natural gas rate review with the Nebraska Public Service Commission (NPSC). Interim rates, which increased base natural gas rates $2.3 million, were implemented on October 1, 2024. In April 2025, we reached a settlement agreement with certain parties for a base rate annual revenue increase of $2.4 million. In June 2025, the NPSC approved this settlement agreement and final rates were implemented on July 1, 2025.

(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.

On July 4, 2025, the One Big Beautiful Bill Act ("OBBB") was signed into law, which includes significant changes to the U.S. tax code and related laws. Key provisions of the OBBB include modifications and extensions to certain provisions of the Tax Cuts and Jobs Act of 2017, changes to interest expense limitations, and updates to energy-related tax incentives. We have evaluated the potential impact of the OBBB to our financial statements and determined that the impact is not material.

During the three months ended June 30, 2025 income tax expense was $3.4 million compared to $4.2 million for the same period in 2024. For the three months ended June 30, 2025, the effective tax rate was 13.7% compared to 11.8% for the same period in 2024. 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.

During the six months ended June 30, 2025 income tax expense was $18.6 million compared to $14.6 million for the same period in 2024. For the six months ended June 30, 2025, the effective tax rate was 15.9% compared to 13.1% for the same period in 2024. 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, 2025			June 30, 2024		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 4	$ —	$ 4	$ (1)	$ —	$ (1)
Reclassification of net income on derivative instruments	153	(40)	113	153	(40)	113
Other comprehensive income (loss)	$ 157	$ (40)	$ 117	$ 152	$ (40)	$ 112

	Six Months Ended					
	June 30, 2025			June 30, 2024		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 5	$ —	$ 5	$ (2)	$ —	$ (2)
Reclassification of net income on derivative instruments	306	(80)	226	306	(80)	226
Other comprehensive income (loss)	$ 311	$ (80)	$ 231	$ 304	$ (80)	$ 224

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, 2025	December 31, 2024
Foreign currency translation	$ 1,438	$ 1,433
Derivative instruments designated as cash flow hedges	(8,695)	(8,921)
Postretirement medical plans	784	784
Accumulated other comprehensive loss	$ (6,473)	$ (6,704)

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

	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	Three Months Ended June 30, 2024			
		Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,260)	$ 280	$ 1,436	$ (7,544)
Other comprehensive loss before reclassifications		—	—	(1)	(1)
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income (loss)		113	—	(1)	112
Ending balance		$ (9,147)	$ 280	$ 1,435	$ (7,432)

	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	Defined Benefit Pension Plan and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,921)	$ 784	$ 1,433	$ (6,704)
Other comprehensive loss 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)

	Affected Line Item in the Condensed Consolidated Statements of Income	Six Months Ended June 30, 2024 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)
Other comprehensive loss before reclassifications		—	—	(2)	(2)
Amounts reclassified from AOCL	Interest Expense	226	—	—	226
Net current-period other comprehensive income (loss)		226	—	(2)	224
Ending balance		$ (9,147)	$ 280	$ 1,435	$ (7,432)

(6) Financing Activities

On March 21, 2025, NW Corp issued and sold $400.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.07 percent maturing on March 21, 2030. These bonds were issued and sold to certain initial purchasers without being registered under the Securities Act of 1933, as amended (Securities Act), in reliance upon exemptions therefrom in compliance with Rule 144A under the Securities Act, or under Regulation S under the Securities Act for sales to non-U.S. persons. Proceeds were utilized to redeem NW Corp's $161.0 million of 5.01 percent Montana First Mortgage Bonds due May 1, 2025 and $75.0 million of 3.11 percent Montana First Mortgage Bonds due July 1, 2025, to repay outstanding borrowings under our NW Corp revolving credit facility, and for general utility purposes.

On April 11, 2025, we amended our existing NorthWestern Energy Group $100.0 million Term Loan Credit Agreement to extend the maturity date from April 11, 2025 to April 10, 2026.

On May 1, 2025, NWE Public Service issued and sold $100.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.49 percent maturing on May 1, 2035. These bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933. Proceeds were utilized to repay at maturity $64.0 million of NWE Public Service's 5.01 percent South Dakota First Mortgage Bonds due on May 1, 2025 and for other general utility purposes.

(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, 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	$ 24,874	$ (2,678)	$ 22,196
Reconciliation to consolidated net income			
Other, net[1]			(968)
Consolidated net income			$ 21,228

Three Months Ended June 30, 2024	Electric	Gas	Total
Operating revenues	$ 260,134	$ 59,795	$ 319,929
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	60,887	15,593	76,480
Operating, general, and administrative	66,761	21,721	88,482
Property and other taxes	28,006	8,251	36,257
Depreciation and depletion	47,546	9,387	56,933
Interest expense, net	(23,298)	(7,147)	(30,445)
Other income, net	4,031	927	4,958
Income tax (expense) benefit	(3,891)	304	(3,587)
Segment net income	$ 33,776	$ (1,073)	$ 32,703
Reconciliation to consolidated net income			
Other, net[1]			(1,049)
Consolidated net income			$ 31,654

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

Six Months Ended June 30, 2024	Electric	Gas	Total
Operating revenues	$ 603,320	$ 191,951	$ 795,271
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	176,228	74,973	251,201
Operating, general, and administrative	134,979	45,650	180,629
Property and other taxes	64,306	19,120	83,426
Depreciation and depletion	94,850	18,826	113,676
Interest expense, net	(47,955)	(13,396)	(61,351)
Other income, net	9,492	1,981	11,473
Income tax expense	(11,174)	(2,869)	(14,043)
Segment net income	$ 83,320	$ 19,098	$ 102,418
Reconciliation to consolidated net income			
Other, net[(1)]			(5,678)
Consolidated net income			$ 96,740

(1) Consists of unallocated corporate 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 millions):

	Three Months Ended					
	June 30, 2025			June 30, 2024		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 81.8	$ 18.0	$ 99.8	$ 86.0	$ 18.9	$ 104.9
South Dakota	16.2	5.6	21.8	15.4	5.9	21.3
Nebraska	—	4.5	4.5	—	3.8	3.8
Residential	**98.0**	**28.1**	**126.1**	**101.4**	**28.6**	**130.0**
Montana	93.9	10.4	104.3	99.7	10.7	110.4
South Dakota	27.8	3.9	31.7	26.3	3.7	30.0
Nebraska	—	2.4	2.4	—	2.0	2.0
Commercial	**121.7**	**16.7**	**138.4**	**126.0**	**16.4**	**142.4**
Industrial	9.9	0.1	10.0	11.3	0.2	11.5
Lighting, governmental, irrigation, and interdepartmental	9.4	0.3	9.7	8.6	0.3	8.9
Total Retail Revenues	**239.0**	**45.2**	**284.2**	**247.3**	**45.5**	**292.8**
Regulatory Amortization	10.3	5.2	15.5	(10.9)	3.7	(7.2)
Transmission	28.1	—	28.1	22.4	—	22.4
Transportation, wholesale and other	2.1	12.8	14.9	1.3	10.6	11.9
Total Revenues[(1)]	**$ 279.5**	**$ 63.2**	**$ 342.7**	**$ 260.1**	**$ 59.8**	**$ 319.9**

	Six Months Ended					
	June 30, 2025			June 30, 2024		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 196.8	$ 69.4	$ 266.2	$ 203.4	$ 67.5	$ 270.9
South Dakota	38.5	21.2	59.7	34.7	19.5	54.2
Nebraska	—	17.7	17.7	—	14.3	14.3
Residential	**235.3**	**108.3**	**343.6**	**238.1**	**101.3**	**339.4**
Montana	190.9	37.2	228.1	201.2	35.8	237.0
South Dakota	57.1	15.1	72.2	54.1	13.0	67.1
Nebraska	—	9.8	9.8	—	8.2	8.2
Commercial	**248.0**	**62.1**	**310.1**	**255.3**	**57.0**	**312.3**
Industrial	20.0	0.6	20.6	23.0	0.6	23.6
Lighting, governmental, irrigation, and interdepartmental	14.0	0.8	14.8	13.3	0.9	14.2
Total Retail Revenues	**517.3**	**171.8**	**689.1**	**529.7**	**159.8**	**689.5**
Regulatory Amortization	38.0	(4.2)	33.8	25.5	10.6	36.1
Transmission	54.7	—	54.7	44.8	—	44.8
Transportation, wholesale and other	5.0	26.7	31.7	3.3	21.6	24.9
Total Revenues[1]	**$ 615.0**	**$ 194.3**	**$ 809.3**	**$ 603.3**	**$ 192.0**	**$ 795.3**

(1) Certain amounts in the prior period have been reclassified to conform with current period presentation. These reclassifications have no effect on the reported financial results.

(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, 2025	June 30, 2024
Basic computation	61,380,777	61,288,870
Dilutive effect of:		
Performance share awards[1]	103,169	68,478
Diluted computation	61,483,946	61,357,348

(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.

	Six Months Ended	
	June 30, 2025	June 30, 2024
Basic computation	61,360,252	61,277,418
Dilutive effect of:		
Performance share awards[1]	95,733	56,065
Diluted computation	61,455,985	61,333,483

As of June 30, 2025, there were 68,107 shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations, compared to 35,933 shares as of June 30, 2024.

(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,	
	2025	2024	2025	2024
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 1,167	$ 1,378	$ 66	$ 74
Interest cost	6,104	5,739	129	132
Expected return on plan assets	(5,734)	(6,335)	(355)	(321)
Amortization of prior service credit	—	—	—	—
Recognized actuarial loss (gain)	—	6	(68)	(25)
Net periodic benefit cost (credit)	$ 1,537	$ 788	$ (228)	$ (140)

	Pension Benefits		Other Postretirement Benefits	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 2,362	$ 2,796	$ 128	$ 154
Interest cost	12,149	11,472	256	279
Expected return on plan assets	(11,476)	(12,663)	(709)	(640)
Amortization of prior service credit	—	—	—	—
Recognized actuarial loss (gain)	—	17	(138)	(37)
Net periodic benefit cost (credit)	$ 3,035	$ 1,622	$ (463)	$ (244)

We contributed $4.2 million to our pension plans during the six months ended June 30, 2025. We expect to contribute an additional $5.8 million to our pension plans during the remainder of 2025.

(11) Commitments and Contingencies

ENVIRONMENTAL LIABILITIES AND REGULATION

Except as set forth below, the circumstances set forth in Note 18 - 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, 2024 appropriately represent, in all material respects, the current status of our environmental liabilities and regulation.

Environmental Protection Agency (EPA) Rules

On April 25, 2024, the EPA released final rules related to greenhouse gas (GHG) emission standards (GHG Rules) for existing coal-fired facilities and new coal and natural gas-fired facilities as well as final rules strengthening the MATS requirements (MATS Rules). Compliance with the rules would require expensive upgrades at Colstrip Units 3 and 4 with proposed compliance dates that may not be achievable and / or require technology that is unproven, resulting in significant impacts to costs of the facilities. The final MATS and GHG Rules require compliance as early as 2027 and 2032, respectively.

Previous efforts by the EPA were met with extensive litigation, and this time is no different. We, along with many other utilities, electric cooperatives, organizations, and states, have petitioned for judicial review of the GHG and MATS Rules with the U.S. Court of Appeals for the D.C. Circuit. The United States Supreme Court denied the multiple stay requests related to the MATS Rule and the GHG Rule. The litigation on the merits continues for both the MATS and GHG rules in the D.C. Circuit Court of Appeals, and the cases could be decided in 2025.

On April 8, 2025, President Trump issued a proclamation, "Regulatory Relief for Certain Stationary Sources to Promote American Energy," exempting certain coal plants, including Colstrip Units 3 and 4, Big Stone Plant, and Coyote Plant, from compliance with the MATS Rule through July 8, 2029. If the MATS Rules and GHG Rules are fully implemented, it would result in additional material compliance costs for us. On June 11, 2025, the EPA issued a Notice of Proposed Rulemaking containing two proposals to reform GHG regulations. If either the lead or alternative proposal is adopted, our additional material compliance costs would be eliminated. A virtual public hearing on this Notice of Proposed Rulemaking was held on July 8, 2025, and final comments to this rulemaking are due back by August 7, 2025. On June 11, 2025, the EPA also issued a Notice of Proposed Rulemaking to rescind the 2024 MATS Rule, which if enacted, would restore the original 2012 MATS standards. A virtual public hearing on this Notice of Proposed Rulemaking was held on July 10, 2025, and final comments are due by August 11, 2025. There is no mandated timeline from the close of public comment to the time when the final rules are published.

These GHG Rules and MATS Rules as well as future additional environmental requirements - federal or state - could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Technology to efficiently capture, remove and/or sequester such GHG emissions or hazardous air pollutants may not be available within a timeframe consistent with the implementation of any such requirements.

LEGAL PROCEEDINGS

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our, and formerly Talen's, hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

The litigation has a long prior history in state and federal court, including before the United States Supreme Court, as detailed in Note 18 - 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, 2024. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). On August 1, 2018, the Federal District Court granted our and Talen's motions to dismiss the State's Complaint as it pertains to the navigability of the riverbeds associated with four of our hydroelectric facilities near Great Falls. The Federal District Court held a bench trial from January 4 to January 18, 2022, which addressed the issue of navigability concerning our other six facilities. On August 25, 2023, the Federal District Court issued its Findings of Fact, Conclusions of Law, and Order (the "Order"), which found all but one of the segments of the riverbeds in dispute not navigable, and thus not owned by the State of Montana. The one segment found navigable, and thus owned by the State, was the segment on which the Black Eagle development was located. Upon the State's motion, the Federal District Court certified the Order for interlocutory appeal to the 9th Circuit Court of Appeals. After briefing and oral argument, the 9th Circuit affirmed the Federal District Court's Order in full on March 4, 2025.

Following the mandate and remand, the District Court will resume jurisdiction to determine damages for the Sun River to Black Eagle Falls Segment of the Missouri River. If the Federal District Court calculates damages as the State District Court did in 2008, we do not anticipate the resulting annual rent for the Black Eagle segment would have a material impact to our financial position or results of operations. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

Other Legal Proceedings

We are also subject to various other 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 842,100 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, 2024.

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, 2025 and 2024.

HOW WE PERFORMED AGAINST OUR SECOND QUARTER 2024 RESULTS

	Three Months Ended June 30, 2025 vs. 2024		
	Income Before Income Taxes	Income Tax (Expense) Benefit[3]	Net Income
	(in millions)		
Second Quarter, 2024	**$ 35.9**	**$ (4.2)**	**$ 31.7**
*Variance in **revenue** and fuel, purchased supply, and direct transmission expense[1] items impacting net income:*			
Rates	19.4	(4.9)	14.5
Electric transmission revenue	5.7	(1.4)	4.3
Natural gas transportation	1.6	(0.4)	1.2
Production tax credits, offset within income tax benefit	1.2	(1.2)	—
Natural gas retail volumes	(4.0)	1.0	(3.0)
Montana property tax tracker collections	(4.3)	1.1	(3.2)
Electric retail volumes	(2.9)	0.7	(2.2)
Non-recoverable Montana electric supply costs	(2.0)	0.5	(1.5)
Other	(0.2)	0.1	(0.1)
*Variance in **expense** items[2] impacting net income:*			
Depreciation	(5.5)	1.4	(4.1)
Interest expense	(4.4)	1.1	(3.3)
Operating, maintenance, and administrative	(10.0)	2.5	(7.5)
Property and other taxes not recoverable within trackers	(1.5)	0.4	(1.1)
Other	(4.4)	(0.1)	(4.5)
Second Quarter, 2025	**$ 24.6**	**$ (3.4)**	**$ 21.2**
Change in Net Income			**$ (10.5)**

(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, 2025 was $21.2 million as compared with $31.7 million for the same period in 2024. This decrease was primarily due to lower retail natural gas and electric usage primarily driven by weather, Montana property tax tracker collections, non-recoverable Montana electric supply costs, depreciation, operating, administrative and general costs, and interest expense. These were partly offset by higher retail rates, higher electric transmission, and natural gas transportation revenues.

SIGNIFICANT TRENDS AND REGULATION

Refer to the NorthWestern Energy Group Annual Report on the Form 10-K for the year ended December 31, 2024 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:

Regulatory Update

Montana Rate Review - In July 2024, we filed a Montana electric and natural gas rate review with the MPSC. In November 2024, the MPSC partially approved our requested interim rates effective December 1, 2024, subject to refund. Subsequently, we modified our request through rebuttal testimony. In March 2025, we filed a natural gas settlement with certain parties. In April 2025, we filed a partial electric settlement with certain other parties. Both settlements are subject to approval by the MPSC.

The partial electric settlement includes, among other things, agreement on base revenue increases (excluding base revenues associated with YCGS), allocated cost of service, rate design, updates to the amount of revenues associated with property taxes (excluding property taxes associated with YCGS), regulatory policy issues related to requested changes in regulatory mechanisms, and agreement to support a separate motion for revised electric interim rates. The partial electric settlement provides for the deferral and annual recovery of incremental operating costs related to wildfire mitigation and insurance expenses through the Wildfire Mitigation Balancing Account.

The natural gas settlement includes, among other things, agreement on base revenues, allocated cost of service, rate design, updates to the amount of revenues associated with property taxes, and agreement to support a separate motion for revised natural gas interim rates.

The details of our filing request, as adjusted in rebuttal testimony are set forth below:

Requested Revenue Increase (Decrease) Through Rebuttal Testimony (in millions)

	Electric	Natural Gas
Base Rates	$ 153.8	27.9
PCCAM[1]	(94.5)	n/a
Property Tax (tracker base adjustment)[1]	(1.3)	0.1
Total Revenue Increase Requested through Rebuttal Testimony	$ 58.0	$ 28.0

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.

The details of our interim rates granted are set forth below:

Interim Revenue Increase (Decrease) Granted (in millions)

	Electric[1]	Natural Gas[2]
Base Rates	$ 18.4	$ 17.4
PCCAM[3]	(88.0)	n/a
Property Tax (tracker base adjustment)[3][4]	7.4	0.2
Total Interim Revenue Granted	$ (62.2)	$ 17.6

(1) These electric interim rates were effective December 1, 2024, through May 22, 2025. See further discussion on revised electric interim rates below.
(2) These natural gas interim rates were effective December 1, 2024, and are expected to remain in effect until the MPSC final order rates are effective.
(3) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(4) Our requested interim property tax base increase went into effect on January 1, 2025, as part of our 2024 property tax tracker filing.

The details of our settlement agreement are set forth below:

Requested Revenue Increase (Decrease) through Settlement Agreements (in millions)

	Electric[1]	Natural Gas
Base Rates:		
Base Rates (Settled)	$ 66.4	$ 18.0
Base Rates - YCGS (Non-settled)[2][3]	43.9	n/a
Requested Base Rates	110.3	18.0
Pass-through items:		
Property Tax (tracker base adjustment) (Settled)[4]	(5.2)	0.1
Property Tax (tracker base adjustment) - YCGS (Non-settled)[2][4]	4.0	n/a
PCCAM (Non-settled)[2][3][4]	(94.5)	n/a
Requested Pass-Through Rates	(95.7)	0.1
Total Requested Revenue Increase	$ 14.6	$ 18.1

(1) We implemented these electric rates on July 2, 2025, on an interim basis, subject to refund.
(2) These items were not included within the partial electric settlement and will be contested items that are expected to be determined in the MPSC's final order.
(3) Intervenor positions on YCGS propose up to an $11.6 million reduction to the base rate revenue request and an additional $38.4 million decrease to the PCCAM base.
(4) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.

On May 23, 2025, as permitted by Montana statute, we implemented our initially requested electric rates, reflecting a base rate revenue increase of $156.5 million, on an interim basis, subject to refund with interest. Within our June 30, 2025 financial statements, we have deferred base rate revenues collected between May 23, 2025, and June 30, 2025, down to our requested revised electric interim rates of $110.3 million as shown within the above table. As of June 30, 2025, we have deferred approximately $3.5 million of base rate revenues collected. On June 20, 2025, we submitted the revised electric interim rates as shown within the above table to the MPSC for approval. The MPSC subsequently approved this request and the rates were implemented on July 2, 2025.

As discussed above, if the MPSC chooses to accept the intervenors positions on the remaining contested issues or does not accept the Settlement Agreements in its final order, losses related to excess interim revenues collected will be incurred. Additionally, any difference between interim and final approved rates will be refunded to customers with interest. However, if final approved rates are higher than interim rates, we will not recover the difference.

A hearing on the electric and natural gas rate review was held in June 2025, and final briefs are due in August 2025. Interim rates will remain in effect on a refundable basis, with interest, until the MPSC issues a final order.

Nebraska Natural Gas Rate Review - In June 2025, the NPSC approved a settlement agreement increasing base rate annual revenue by $2.4 million and final rates were implemented on July 1, 2025.

EPA Rules

In April 2024, the EPA released GHG Rules for existing coal-fired facilities and new coal and natural gas-fired facilities as well as MATS Rules. Compliance with the rules would require expensive upgrades at Colstrip Units 3 and 4 with proposed compliance dates that may not be achievable and / or require technology that is unproven, resulting in significant impacts to costs of the facilities. The final MATS and GHG Rules require compliance as early as 2027 and 2032, respectively. On April 8, 2025, President Trump issued a proclamation, "Regulatory Relief for Certain Stationary Sources to Promote American Energy," exempting certain coal plants, including Colstrip Units 3 and 4, Big Stone Plant, and Coyote Plant, from compliance with the MATS Rule through July 8, 2029. On June 11, 2025, the EPA issued Notices of Proposed Rulemaking to, among other things, rescind the 2024 MATS Rule. See Note 11 - Commitments and Contingencies to the Condensed Consolidated Financial Statements included herein for additional information regarding these rules.

Acquisition of Energy West Montana Assets

In July 2024, NW Corp entered into an Asset Purchase Agreement with Hope Utilities to acquire its Energy West natural gas distribution and system operations serving approximately 33,000 customers located in Great Falls, Cut Bank, and West Yellowstone, Montana. In May 2025, the MPSC approved this acquisition and on July 1, 2025, NW Corp completed this acquisition for approximately $36.5 million in cash, which is subject to certain post-close working capital adjustments that we expect to finalize in the second half of 2025.

Regional Transmission Development Activities

In August 2024, the U.S. Department of Energy awarded a $700.0 million grant through the Grid Resilience and Innovation Partnership (GRIP) program to advance the North Plains Connector (NPC) Consortium project. The 415-mile, high-voltage direct-current transmission line is intended to connect Montana's Colstrip substation, of which we are the operator and a joint owner, to central North Dakota, bridging the eastern and western U.S. energy grids. The NPC Consortium includes potential upgrades to our jointly owned Colstrip Transmission System and $70.0 million of the award is earmarked for the Colstrip Transmission System Upgrade. The NPC project aims to enhance grid reliability, support renewable energy integration, and provide additional capacity across multiple states. We collaborated with Grid United, the Montana Department of Commerce, and other regional utilities on the successful GRIP grant application.

In addition to the Colstrip Transmission System Upgrade, 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 and initiating regulatory filings with approvals targeted in 2026. Construction is expected to commence in 2028, 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.

President Trump issued an Executive Order on January 20, 2025, "Unleashing American Energy," directing all federal executive agency heads to review all agency actions implicating energy reliability and affordability or potentially burdening the development of domestic energy resources. This Executive Order has delayed the disbursement of the funds granted by the U.S. Department of Energy for the NPC Consortium project.

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.

Montana Wildfire Risk Mitigation

The Montana Legislature approved House Bill 490 in April 2025, with broad bipartisan support in both the House (90-0) and Senate (40-8), and the Governor signed this bill into law in May 2025. This bill requires development, approval, and implementation of electric facilities providers' wildfire mitigation plans. Importantly, House Bill 490 helps address some preexisting liability risks facing electric facilities providers in Montana. It changes Montana law, recognizing utilities' obligation to provide a public service for customers that is different from typical businesses; circumscribes certain damages; and enacts liability protections related to wildfire and wildfire prevention efforts involving providers. More specifically, House Bill 490 precludes common law strict liability claims for damages related to wildfire and electric activities or wildfire mitigation activities; establishes a statutory standard of care, supplanting common law causes of action and other theories of recovery; and creates a rebuttable presumption that an electric facilities provider acted reasonably if it substantially followed an approved wildfire mitigation plan. 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 an electric facilities provider's actions were grossly negligent or intentional. We expect to file our wildfire mitigation plan with the MPSC in the third quarter of 2025 for review and approval.

Montana Large Load Customers

The MPSC requested information on our plan to serve potential large load customers and related resource adequacy issues. We responded in March 2025, outlining our policy and legal positions, emphasizing the importance of economic development for Montana and our commitment to serving our existing customers.

Montana Data Centers

In July 2025, we entered into a nonbinding letter of intent with Quantica Infrastructure to evaluate the transmission infrastructure and generation resources needed to support their proposed Phase 1 need of 5 megawatts in 2026 with growth up to 500 megawatts by 2030. This is our third signed letter of intent for data center load growth. In December 2024, we announced two separate nonbinding letters of intent to provide electric supply services for data centers being developed in Montana with a combined energy service requirement expected to be 75 megawatts beginning in early 2026 with growth of up to 400 megawatts or more by 2030. We anticipate that service could be provided through our regulated business, pending further evaluation and regulatory considerations.

Montana Electric Transmission Construction

In May 2025, Senate Bill 301 was passed by the Montana Legislature with unanimous bipartisan support and signed into law. The intention of this bill is to expedite and streamline the process for a public utility to construct electric transmission lines to serve the increasing demand for electricity, enhance grid reliability, and address current transmission congestion within Montana. This bill allows a public utility to request a Certificate of Public Convenience & Necessity for electric transmission lines rated higher than 69 kilovolts from the MPSC and also provides a process for a public utility to apply for advanced cost approval of electric transmission lines and related facilities before actual construction begins.

Colstrip Acquisitions and Requests for Cost Recovery

As previously disclosed, we entered into definitive agreements with Avista Corporation (Avista) and Puget Sound Energy (Puget) to acquire their respective interests in Colstrip Units 3 and 4 for $0 and expect to complete these acquisitions on December 31, 2025. Accordingly, we will be responsible for associated operating costs on January 1, 2026. Puget and Avista will remain responsible for their respective pre-closing share of environmental 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. During the second half of 2025 we intend to make filings with the MPSC and FERC associated with these transactions, including recovery of incremental operating costs.

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 using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. 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, 2025 Compared with the Three Months Ended June 30, 2024

Consolidated net income for the three months ended June 30, 2025 was $21.2 million as compared with $31.7 million for the same period in 2024. This decrease was primarily due to lower retail natural gas and electric usage primarily driven by weather, Montana property tax tracker collections, non-recoverable Montana electric supply costs, depreciation, operating, administrative and general costs, and interest expense. These were partly offset by higher retail rates, and higher electric transmission and natural gas transportation revenues.

Consolidated gross margin for the three months ended June 30, 2025 was $94.5 million as compared with $92.8 million in 2024, an increase of $1.7 million, or 1.8 percent. This increase was primarily due to higher retail rates, higher electric transmission, and natural gas transportation revenues. These were partly offset by lower retail natural gas and electric usage primarily driven by weather, Montana property tax tracker collections, non-recoverable Montana electric supply costs, depreciation, and operating and maintenance costs.

	Electric		Natural Gas		Total	
	2025	2024	2025	2024	2025	2024
			(in millions)			
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 279.4	$ 260.1	$ 63.3	$ 59.8	$ 342.7	$ 319.9
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	59.6	60.9	15.7	15.6	75.3	76.5
Less: Operating and maintenance	48.6	43.5	13.7	13.9	62.3	57.4
Less: Property and other taxes	37.3	28.0	10.9	8.2	48.2	36.2
Less: Depreciation and depletion	52.4	47.6	10.0	9.4	62.4	57.0
Gross Margin	**81.5**	**80.1**	**13.0**	**12.7**	**94.5**	**92.8**
Operating and maintenance	48.6	43.5	13.7	13.9	62.3	57.4
Property and other taxes	37.3	28.0	10.9	8.2	48.2	36.2
Depreciation and depletion	52.4	47.6	10.0	9.4	62.4	57.0
Utility Margin(1)	**$ 219.8**	**$ 199.2**	**$ 47.6**	**$ 44.2**	**$ 267.4**	**$ 243.4**

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

	Three Months Ended June 30,			
	2025	2024	Change	% Change
	(dollars in millions)			
Utility Margin				
Electric	$ 219.8	$ 199.2	$ 20.6	10.3 %
Natural Gas	47.6	44.2	3.4	7.7
Total Utility Margin(1)	**$ 267.4**	**$ 243.4**	**$ 24.0**	**9.9 %**

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

Consolidated utility margin for the three months ended June 30, 2025 was $267.4 million as compared with $243.4 million for the same period in 2024, an increase of $24.0 million, or 9.9 percent. Primary components of the change in utility margin include the following (in millions):

	Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income	
Interim rates (subject to refund)	$ 17.9
Transmission revenue due to market conditions and rates	5.7
Montana natural gas transportation	1.6
Base rates	1.5
Montana property tax tracker collections	(4.3)
Natural gas retail volumes	(4.0)
Electric retail volumes	(2.9)
Non-recoverable Montana electric supply costs	(2.0)
Other	(0.2)
Change in Utility Margin Items Impacting Net Income	**13.3**
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property and other taxes	10.4
Production tax credits, offset in income tax expense	1.2
Operating expenses recovered in revenue, offset in operating and maintenance expense	(0.9)
Change in Utility Margin Items Offset Within Net Income	**10.7**
Increase in Consolidated Utility Margin(1)	**$ 24.0**

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

Lower electric retail volumes were driven by unfavorable spring weather in all jurisdictions impacting residential demand, and lower commercial and industrial demand, partly offset by customer growth in all jurisdictions. Lower natural gas retail volumes were driven by unfavorable weather in all jurisdictions, partly offset by customer growth in all jurisdictions.

Under the PCCAM, net supply costs higher or lower than the PCCAM base rate (PCCAM Base) (excluding qualifying facility (QF) costs) are allocated 90 percent to Montana customers and 10 percent to shareholders. For the three months ended June 30, 2025, we under-collected supply costs of $7.6 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $0.8 million (10 percent of the PCCAM Base cost variance). For the three months ended June 30, 2024, we over-collected supply costs of $11.0 million resulting in a reduction to our under collection of costs, and recorded an increase in pre-tax earnings of $1.2 million (10 percent of the PCCAM Base cost variance).

	Three Months Ended June 30,			
	2025	**2024**	**Change**	**% Change**
	(dollars in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 62.3	$ 57.4	$ 4.9	8.5 %
Administrative and general	33.8	31.3	2.5	8.0
Property and other taxes	48.2	36.3	11.9	32.8
Depreciation and depletion	62.4	56.9	5.5	9.7
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 206.7**	**$ 181.9**	**$ 24.8**	**13.6 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $206.7 million for the three months ended June 30, 2025, as compared with $181.9 million for the three months ended June 30, 2024. Primary components of the change include the following (in millions):

	Operating Expenses 2025 vs. 2024
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income	
Depreciation expense due to plant additions and higher depreciation rates	$ 5.5
Electric generation maintenance	3.7
Insurance expense, primarily due to increased wildfire risk premiums	3.0
Property and other taxes not recoverable within trackers	1.5
Wildfire mitigation expense, partly offset by higher base revenues	1.4
Labor and benefits[1]	1.3
Technology implementation and maintenance expenses	0.9
Uncollectible accounts	(0.1)
Other	(0.2)
Change in Items Impacting Net Income	**17.0**
Operating Expenses Offset Within Net Income	
Property and other taxes recovered in trackers, offset in revenue	10.4
Deferred compensation, offset in other income	(1.2)
Operating and maintenance expenses recovered in trackers, offset in revenue	(0.9)
Pension and other postretirement benefits, offset in other income[1]	(0.5)
Change in Items Offset Within Net Income	**7.8**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 24.8**

(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.

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, 2025 was $60.8 million as compared with $61.6 million in the same period of 2024. This decrease was primarily due to lower retail natural gas and electric usage primarily driven by weather, Montana property tax tracker collections, non-recoverable Montana electric supply costs, depreciation, and operating, administrative and general costs. These were partly offset by higher retail rates, higher electric transmission, and natural gas transportation revenues.

Consolidated interest expense was $36.3 million for the three months ended June 30, 2025 as compared with $31.9 million for the same period of 2024. This increase was due to higher borrowings and interest rates and lower capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated other income was $0.1 million for the three months ended June 30, 2025 as compared with $6.2 million for the same period of 2024. This decrease was primarily due to lower capitalization of AFUDC, a decrease in the value of deferred shares held in trust for deferred compensation, higher non-service component pension expense, and a $1.0 million expense accrual related to an estimated penalty for the previously disclosed Community Renewable Energy Project (CREP) informed by a recent MPSC ruling.

Consolidated income tax expense was $3.4 million for the three months ended June 30, 2025 as compared to $4.2 million for the same period of 2024. Our effective tax rate for the three months ended June 30, 2025 was 13.7% as compared with 11.8% for the same period in 2024.

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

	Three Months Ended June 30,			
	2025		2024	
Income Before Income Taxes	$ 24.6		$ 35.9	
Income tax calculated at federal statutory rate	5.2	21.0 %	7.5	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	0.1	0.4	0.0	0.1
Flow-through repairs deductions	(2.8)	(11.4)	(3.0)	(8.5)
Production tax credits	(0.6)	(2.4)	(2.0)	(5.6)
Share-based compensation	(0.3)	(1.2)	0.0	0.0
Amortization of excess deferred income tax	(0.1)	(0.4)	(0.2)	(0.5)
Plant and depreciation flow-through items	1.5	6.1	1.1	3.0
Other, net	0.4	1.6	0.8	2.3
	(1.8)	(7.3)	(3.3)	(9.2)
Income tax expense	$ 3.4	13.7 %	$ 4.2	11.8 %

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, 2025 Compared with the Six Months Ended June 30, 2024

Consolidated net income for the six months ended June 30, 2025 was $98.2 million as compared with $96.7 million for the same period in 2024. This increase was primarily due to higher retail rates, higher electric transmission, higher retail electric usage primarily driven by weather, and Montana natural gas transportation. These were offset in part by Montana property tax collections, non-recoverable Montana electric supply costs, depreciation, operating, and administrative and general costs, and interest expense.

Consolidated gross margin for the six months ended June 30, 2025 was $260.9 million as compared with $235.4 million in 2024, an increase of $25.5 million, or 10.8 percent. This increase was primarily due to higher retail rates, higher electric transmission, higher retail electric usage primarily driven by weather, and Montana natural gas transportation. These were offset in part by Montana property tax tracker collections, non-recoverable Montana electric supply costs, depreciation, and operating and maintenance expenses.

	Electric		Natural Gas		Total	
	2025	2024	2025	2024	2025	2024
	(in millions)					
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 615.0	$ 603.3	$ 194.4	$ 192.0	$ 809.4	$ 795.3
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	152.4	176.2	61.1	75.0	213.5	251.2
Less: Operating and maintenance	91.2	83.8	27.8	27.8	119.0	111.6
Less: Property and other taxes	70.6	64.3	20.6	19.1	91.2	83.4
Less: Depreciation and depletion	104.9	94.9	19.9	18.8	124.8	113.7
Gross Margin	**195.9**	**184.1**	**65.0**	**51.3**	**260.9**	**235.4**
Operating and maintenance	91.2	83.8	27.8	27.8	119.0	111.6
Property and other taxes	70.6	64.3	20.6	19.1	91.2	83.4
Depreciation and depletion	104.9	94.9	19.9	18.8	124.8	113.7
Utility Margin(1)	**$ 462.6**	**$ 427.1**	**$ 133.3**	**$ 117.0**	**$ 595.9**	**$ 544.1**

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

	Six Months Ended June 30,			
	2025	2024	Change	% Change
	(dollars in millions)			
Utility Margin				
Electric	$ 462.6	$ 427.1	$ 35.5	8.3 %
Natural Gas	133.3	117.0	16.3	13.9
Total Utility Margin(1)	**$ 595.9**	**$ 544.1**	**$ 51.8**	**9.5 %**

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

Consolidated utility margin for the six months ended June 30, 2025 was $595.9 million as compared with $544.1 million for the same period in 2024, an increase of $51.8 million, or 9.5 percent. Primary components of the change in utility margin include the following (in millions):

	Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income	
Interim rates (subject to refund)	$ 30.1
Transmission revenue due to market conditions and rates	9.9
Base rates	5.8
Electric retail volumes	4.1
Montana natural gas transportation	2.9
Natural gas retail volumes	0.3
Montana property tax tracker collections	(6.8)
Non-recoverable Montana electric supply costs	(1.7)
Other	(0.6)
Change in Utility Margin Items Impacting Net Income	**44.0**
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property and other taxes	6.6
Production tax credits, offset in income tax expense	2.0
Operating expenses recovered in revenue, offset in operating and maintenance expense	(0.8)
Change in Utility Margin Items Offset Within Net Income	**7.8**
Increase in Consolidated Utility Margin[1]	**$ 51.8**

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

Electric retail volume impact was due to higher residential usage in all jurisdictions due to favorable weather, higher commercial demand in Montana, and customer growth in all jurisdictions, partly offset by lower commercial demand in South Dakota, and lower industrial demand. Natural gas retail volumes were impacted by favorable weather in all jurisdictions and customer growth in all jurisdictions.

Under the PCCAM, net supply costs higher or lower than the PCCAM Base (excluding qualifying facility (QF) costs) are allocated 90 percent to Montana customers and 10 percent to shareholders. For the six months ended June 30, 2025, we under-collected supply costs of $31.6 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $3.5 million (10 percent of the PCCAM Base cost variance). For the six months ended June 30, 2024, we under-collected supply costs of $16.1 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $1.8 million (10 percent of the PCCAM Base cost variance).

	Six Months Ended June 30,			
	2025	2024	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 119.0	$ 111.5	$ 7.5	6.7 %
Administrative and general	75.1	71.7	3.4	4.7
Property and other taxes	91.4	83.4	8.0	9.6
Depreciation and depletion	124.8	113.7	11.1	9.8
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 410.3**	**$ 380.3**	**$ 30.0**	**7.9 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $410.3 million for the six months ended June 30, 2025, as compared with $380.3 million for the six months ended June 30, 2024. Primary components of the change include the following (in millions):

	Operating Expenses 2025 vs. 2024
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income	
Depreciation expense due to plant additions and higher depreciation rates	$ 11.1
Electric generation maintenance	7.2
Insurance expense, primarily due to increased wildfire risk premiums	6.3
Labor and benefits[1]	2.4
Wildfire mitigation expense, partly offset by higher base revenues	1.4
Property and other taxes not recoverable within trackers	1.4
Technology implementation and maintenance expenses	1.4
Uncollectible accounts	0.3
Litigation outcome (Pacific Northwest Solar)	(2.4)
Non-cash impairment of alternative energy storage investment	(2.2)
Other	(2.7)
Change in Items Impacting Net Income	**24.2**
Operating Expenses Offset Within Net Income	
Property and other taxes recovered in trackers, offset in revenue	6.6
Operating and maintenance expenses recovered in trackers, offset in revenue	(0.8)
Change in Items Offset Within Net Income	**5.8**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 30.0**

(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, 2025 was $185.5 million as compared with $163.7 million in the same period of 2024. This increase was primarily due to higher retail rates, higher electric transmission, higher retail electric usage primarily driven by weather, and Montana natural gas transportation. These were offset in part by Montana property tax collections, non-recoverable Montana electric supply costs, depreciation, and operating, administrative and general costs.

Consolidated interest expense was $72.8 million for the six months ended June 30, 2025 as compared with $62.9 million for the same period of 2024. This increase was due to higher borrowings and interest rates and lower capitalization of AFUDC.

Consolidated other income was $4.0 million for the six months ended June 30, 2025 as compared to $10.5 million during the same period of 2024. This decrease was primarily due to lower capitalization of AFUDC, a prior year reversal of $2.3 million from a previously disclosed CREP penalty due to a favorable legal ruling, and a $1.0 million expense accrual related to an estimated penalty for the CREP informed by a recent MPSC ruling, partly offset by an increase of $2.5 million driven by a prior year non-cash impairment of an alternative energy storage equity investment.

Consolidated income tax expense for the six months ended June 30, 2025 was $18.6 million as compared to $14.6 million in the same period of 2024. Our effective tax rate for the six months ended June 30, 2025 was 15.9% as compared with 13.1% for the same period in 2024.

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

	Six Months Ended June 30,			
	2025		2024	
Income Before Income Taxes	$ 116.8		$ 111.3	
Income tax calculated at federal statutory rate	24.5	21.0 %	23.4	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	0.9	0.8	0.7	0.6
Flow-through repairs deductions	(10.8)	(9.2)	(9.2)	(8.3)
Production tax credits	(2.7)	(2.3)	(5.0)	(4.5)
Amortization of excess deferred income tax	(0.8)	(0.7)	(0.6)	(0.5)
Share-based compensation	(0.3)	(0.3)	0.3	0.3
Plant and depreciation flow-through items	6.8	5.8	4.1	3.7
Other, net	1.0	0.8	0.9	0.8
	(5.9)	(5.1)	(8.8)	(7.9)
Income tax expense	$ 18.6	15.9 %	$ 14.6	13.1 %

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 are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expense.

Three Months Ended June 30, 2025 Compared with the Three Months Ended June 30, 2024

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2025	2024	$	%	2025	2024	2025	2024
	(in thousands)							
Montana	$ 81,824	$ 86,028	$ (4,204)	(4.9)%	571	582	333,302	327,655
South Dakota	16,235	15,392	843	5.5	113	117	51,663	51,340
Residential	**98,059**	**101,420**	**(3,361)**	**(3.3)**	**684**	**699**	**384,965**	**378,995**
Montana	93,910	99,655	(5,745)	(5.8)	754	756	77,173	75,602
South Dakota	27,737	26,356	1,381	5.2	246	259	13,182	13,083
Commercial	**121,647**	**126,011**	**(4,364)**	**(3.5)**	**1,000**	**1,015**	**90,355**	**88,685**
Industrial	9,888	11,282	(1,394)	(12.4)	684	739	80	80
Other(1)	9,421	8,550	871	10.2	42	36	28,761	28,555
Total Retail Electric	**$ 239,015**	**$ 247,263**	**$ (8,248)**	**(3.3)%**	**2,410**	**2,489**	**504,161**	**496,315**
Regulatory amortization	10,325	(10,904)	21,229	194.7				
Transmission	28,147	22,436	5,711	25.5				
Wholesale and Other	1,981	1,339	642	47.9				
Total Revenues	**$ 279,468**	**$ 260,134**	**$ 19,334**	**7.4 %**				
Fuel, purchased supply and direct transmission expense(2)	**59,603**	**60,887**	**(1,284)**	**(2.1)**				
Utility Margin(3)	**$ 219,865**	**$ 199,247**	**$ 20,618**	**10.3 %**				

(1) Included within this line is our lighting customer class, which we have historically counted each lighting district as one customer. We have retroactively modified our customer counts to now reflect each lighting service as a customer as that better aligns with the MWH usage of this customer class.
(2) Exclusive of depreciation and depletion.
(3) 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			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana	55	43	66	28% warmer	17% cooler
South Dakota	99	54	73	83% warmer	36% warmer

	Heating Degree Days			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana(1)	1,033	1,154	1,131	10% warmer	9% warmer
South Dakota	1,223	1,333	1,454	8% warmer	16% 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, 2025 and 2024 (in millions):

		Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income		
Interim Rates (subject to refund)	$	14.7
Transmission revenue due to market conditions and rates		5.7
Montana property tax tracker collections		(3.1)
Retail volumes		(2.9)
Non-recoverable Montana electric supply costs		(2.0)
Other		(0.1)
Change in Utility Margin Items Impacting Net Income		12.3
Utility Margin Items Offset Within Net Income		
Property and other taxes recovered in revenue, offset in property and other taxes		8.0
Production tax credits, offset in income tax expense		1.2
Operating expenses recovered in revenue, offset in operating and maintenance expense		(0.9)
Change in Utility Margin Items Offset Within Net Income		8.3
Increase in Utility Margin[(1)]	**$**	**20.6**

(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.

Lower electric retail volumes were driven by unfavorable spring weather in all jurisdictions impacting residential demand, and lower commercial and industrial demand, partly offset by customer growth in all jurisdictions.

Under the PCCAM, net supply costs higher or lower than the PCCAM base rate (PCCAM Base) (excluding qualifying facility (QF) costs) are allocated 90 percent to Montana customers and 10 percent to shareholders. For the three months ended June 30, 2025, we under-collected supply costs of $7.6 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $0.8 million (10 percent of the PCCAM Base cost variance). For the three months ended June 30, 2024, we over-collected supply costs of $11.0 million resulting in a reduction to our under collection of costs, and recorded an increase in pre-tax earnings of $1.2 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, 2025 Compared with the Six Months Ended June 30, 2024

	Revenues		Change		Megawatt Hours (MWH)		Avg. Customer Counts	
	2025	2024	$	%	2025	2024	2025	2024
	(in thousands)							
Montana	$ 196,801	$ 203,391	$ (6,590)	(3.2)%	1,473	1,429	332,820	326,986
South Dakota	38,527	34,702	3,825	11.0	308	290	51,727	51,396
Residential	**235,328**	**238,093**	**(2,765)**	**(1.2)**	**1,781**	**1,719**	**384,547**	**378,382**
Montana	190,862	201,158	(10,296)	(5.1)	1,600	1,580	77,296	75,639
South Dakota	57,051	54,128	2,923	5.4	530	546	13,156	13,047
Commercial	**247,913**	**255,286**	**(7,373)**	**(2.9)**	**2,130**	**2,126**	**90,452**	**88,686**
Industrial	19,988	22,951	(2,963)	(12.9)	1,388	1,464	80	80
Other[1]	14,114	13,366	748	5.6	54	49	27,895	27,793
Total Retail Electric	**$ 517,343**	**$ 529,696**	**$ (12,353)**	**(2.3)%**	**5,353**	**5,358**	**502,974**	**494,941**
Regulatory amortization	38,015	25,442	12,573	49.4				
Transmission	54,703	44,824	9,879	22.0				
Wholesale and Other	4,890	3,358	1,532	45.6				
Total Revenues	**$ 614,951**	**$ 603,320**	**$ 11,631**	**1.9 %**				
Fuel, purchased supply and direct transmission expense[2]	**152,355**	**176,228**	**(23,873)**	**(13.5)**				
Utility Margin[3]	**$ 462,596**	**$ 427,092**	**$ 35,504**	**8.3 %**				

(1) Included within this line is our lighting customer class, which we have historically counted each lighting district as one customer. We have retroactively modified our customer counts to now reflect each lighting service as a customer as that better aligns with the MWH usage of this customer class.
(2) Exclusive of depreciation and depletion.
(3) 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			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana[1]	55	43	66	28% warmer	17% cooler
South Dakota	99	54	73	83% warmer	36% warmer

	Heating Degree Days			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana[1]	4,553	4,492	4,454	1% colder	2% colder
South Dakota	5,230	4,808	5,615	9% colder	7% 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, 2025 and 2024 (in millions):

		Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income		
Interim rates (subject to refund)	$	19.9
Transmission revenue due to market conditions and rates		9.9
Retail volumes		4.1
Base rates		1.7
Montana property tax tracker collections		(4.6)
Non-recoverable Montana electric supply costs		(1.7)
Other		(0.2)
Change in Utility Margin Items Impacting Net Income		29.1
Utility Margin Items Offset Within Net Income		
Property and other taxes recovered in revenue, offset in property and other taxes		5.3
Production tax credits, offset in income tax expense		2.0
Operating expenses recovered in revenue, offset in operating and maintenance expense		(0.9)
Change in Utility Margin Items Offset Within Net Income		6.4
Increase in Utility Margin(1)	**$**	**35.5**

(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 volume impact was favorable due to higher residential usage in all jurisdictions due to favorable weather, higher commercial demand in Montana, and customer growth in all jurisdictions, partly offset by lower commercial demand in South Dakota, and lower industrial demand.

Under the PCCAM, net supply costs higher or lower than the PCCAM Base (excluding qualifying facility (QF) costs) are allocated 90 percent to Montana customers and 10 percent to shareholders. For the six months ended June 30, 2025, we under-collected supply costs of $31.6 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $3.5 million (10 percent of the PCCAM Base cost variance). For the six months ended June 30, 2024, we under-collected supply costs of $16.1 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $1.8 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, 2025 Compared with the Three Months Ended June 30, 2024

	Revenues		Change		Dekatherms (Dkt)		Avg. Customer Counts	
	2025	2024	$	%	2025	2024	2025	2024
	(in thousands)							
Montana	$ 17,968	$ 18,921	$ (953)	(5.0) %	1,949	2,224	187,134	185,449
South Dakota	5,566	5,894	(328)	(5.6)	524	568	42,821	42,440
Nebraska	4,523	3,798	725	19.1	391	438	37,907	37,889
Residential	**28,057**	**28,613**	**(556)**	**(1.9)**	**2,864**	**3,230**	**267,862**	**265,778**
Montana	10,499	10,743	(244)	(2.3)	1,181	1,301	26,613	26,160
South Dakota	3,920	3,754	166	4.4	593	600	7,549	7,354
Nebraska	2,346	1,969	377	19.1	308	333	5,098	5,044
Commercial	**16,765**	**16,466**	**299**	**1.8**	**2,082**	**2,234**	**39,260**	**38,558**
Industrial	144	169	(25)	(14.8)	17	23	239	237
Other	270	292	(22)	(7.5)	38	44	207	196
Total Retail Gas	**$ 45,236**	**$ 45,540**	**$ (304)**	**(0.7)%**	**5,001**	**5,531**	**307,568**	**304,769**
Regulatory amortization	5,189	3,735	1,454	38.9				
Transportation, wholesale and other	12,820	10,520	2,300	21.9				
Total Revenues	**$ 63,245**	**$ 59,795**	**$ 3,450**	**5.8 %**				
Fuel, purchased supply and direct transmission expense(1)	**15,668**	**15,593**	**75**	**0.5**				
Utility Margin(2)	**$ 47,577**	**$ 44,202**	**$ 3,375**	**7.6 %**				

(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			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana(1)	1,093	1,209	1,176	10% warmer	7% warmer
South Dakota	1,223	1,333	1,454	8% warmer	16% warmer
Nebraska	959	985	1,109	3% warmer	14% 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, 2025 and 2024:

	Utility Margin 2025 vs. 2024 (in millions)
Utility Margin Items Impacting Net Income	
Interim rates (subject to refund)	$ 3.2
Montana natural gas transportation	1.6
Base rates	1.5
Retail volumes	(4.0)
Montana property tax tracker collections	(1.2)
Other	(0.1)
Change in Utility Margin Items Impacting Net Income	1.0
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property and other taxes	2.4
Change in Utility Margin Items Offset Within Net Income	2.4
Increase in Utility Margin[(1)]	**$ 3.4**

(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.

Lower retail volumes were driven by unfavorable weather in all jurisdictions, partly offset by customer growth in all jurisdictions.

Six Months Ended June 30, 2025 Compared with the Six Months Ended June 30, 2024

	Revenues		Change		Dekatherms (Dkt)		Avg. Customer Counts	
	2025	2024	$	%	2025	2024	2025	2024
	(in thousands)							
Montana	$ 69,386	$ 67,511	$ 1,875	2.8 %	8,466	8,482	187,066	185,332
South Dakota	21,136	19,499	1,637	8.4	2,311	2,005	42,941	42,521
Nebraska	17,732	14,315	3,417	23.9	1,773	1,669	38,023	37,970
Residential	**108,254**	**101,325**	**6,929**	**6.8**	**12,550**	**12,156**	**268,030**	**265,823**
Montana	37,257	35,826	1,431	4.0	4,813	4,698	26,588	26,121
South Dakota	15,095	13,021	2,074	15.9	2,203	1,914	7,545	7,362
Nebraska	9,787	8,188	1,599	19.5	1,254	1,192	5,122	5,063
Commercial	**62,139**	**57,035**	**5,104**	**8.9**	**8,270**	**7,804**	**39,255**	**38,546**
Industrial	628	588	40	6.8	86	83	238	237
Other	861	868	(7)	(0.8)	132	133	207	196
Total Retail Gas	**$ 171,882**	**$ 159,816**	**$ 12,066**	**7.5 %**	**21,038**	**20,176**	**307,730**	**304,802**
Regulatory amortization	(4,247)	10,661	(14,908)	(139.8)				
Transportation, wholesale and other	26,757	21,474	5,283	24.6				
Total Revenues	**$ 194,392**	**$ 191,951**	**$ 2,441**	**1.3 %**				
Fuel, purchased supply and direct transmission expense(1)	**61,113**	**74,973**	**(13,860)**	**(18.5)**				
Utility Margin(2)	**$ 133,279**	**$ 116,978**	**$ 16,301**	**13.9 %**				

(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			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana(1)	4,590	4,589	4,537	remained flat	1% colder
South Dakota	5,230	4,808	5,615	9% colder	7% warmer
Nebraska	4,368	3,978	4,436	10% colder	2% 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, 2025 and 2024:

	Utility Margin 2025 vs. 2024 (in millions)
Utility Margin Items Impacting Net Income	
Interim rates (subject to refund)	$ 10.2
Base rates	4.1
Montana natural gas transportation	2.9
Retail volumes	0.3
Montana property tax tracker collections	(2.2)
Other	(0.4)
Change in Utility Margin Items Impacting Net Income	14.9
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property tax expense	1.3
Operating expenses recovered in revenue, offset in operating and maintenance expense	0.1
Change in Utility Margin Items Offset Within Net Income	1.4
Increase in Utility Margin(1)	**$ 16.3**

(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.

Higher retail volumes were driven by favorable weather in all jurisdictions and customer growth in all jurisdictions.

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 16 - Common Stock in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2024 for further information regarding these dividend restrictions. As of June 30, 2025, 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, 2025, our total net liquidity was approximately $317.9 million, including $2.9 million of cash and cash equivalents and $315.0 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,	
	2025	2024
Operating Activities		
Net income	$ 98.2	$ 96.7
Adjustments to reconcile net income to cash provided by operations	144.1	128.1
Changes in working capital	(22.1)	1.0
Other noncurrent assets and liabilities	(8.6)	(1.9)
Cash Provided by Operating Activities	**211.6**	**223.9**
Investing Activities		
Property, plant and equipment additions	(221.0)	(247.4)
Investment in debt & equity securities	(5.8)	(0.9)
Cash Used in Investing Activities	**(226.8)**	**(248.3)**
Financing Activities		
Issuance of long-term debt	500.0	215.0
Issuance of short-term borrowings	—	100.0
Repayments on long-term debt	(300.0)	(100.0)
Line of credit repayments, net	(103.0)	(105.0)
Dividends on common stock	(80.7)	(79.3)
Other financing activities, net	(3.6)	(0.5)
Cash Provided by Financing Activities	**12.7**	**30.2**
(Decrease) Increase in Cash, Cash Equivalents, and Restricted Cash	**(2.5)**	**5.8**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	29.0	25.2
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 26.5**	**$ 31.0**

Operating Activities

As of June 30, 2025, cash, cash equivalents, and restricted cash were $26.5 million as compared with $29.0 million as of December 31, 2024 and $31.0 million as of June 30, 2024. Cash provided by operating activities totaled $211.6 million for the six months ended June 30, 2025 as compared with $223.9 million during the six months ended June 30, 2024. 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, 2025, and are affected by changes in working capital. The decrease in cash provided by operating activities is primarily due to lower collections of accounts receivable balances due to timing of colder weather and an increase 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
2024	$ 7.8	$ 14.9	$ (7.1)
2025	$ 5.9	$ 28.6	$ (22.7)
		Increase in net cash outflows	$ (15.6)

Investing Activities

Cash used in investing activities totaled $226.8 million during the six months ended June 30, 2025, as compared with $248.3 million during the six months ended June 30, 2024. Plant additions during the first six months of 2025 include maintenance additions of approximately $149.4 million and capacity related capital expenditures of $71.6 million. Plant additions during the first six months of 2024 included maintenance additions of approximately $130.5 million and capacity related capital expenditures of approximately $116.9 million.

Financing Activities

Cash provided by financing activities totaled $12.7 million during the six months ended June 30, 2025, as compared with $30.2 million during the six months ended June 30, 2024. During the six months ended June 30, 2025, cash provided by financing activities reflects proceeds from the issuance of 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. During the six months ended June 30, 2024, cash provided by financing activities reflects proceeds from the issuance of debt of $215.0 million and short-term borrowings of $100.0 million, partly offset by net repayments under our revolving lines of credit of $105.0 million, repayment of $100.0 million of Montana First Mortgage Bonds and payment of dividends of $79.3 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, 2024 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, 2025, 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 10 - Short-

Term Borrowings and Credit Arrangements in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2024.

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 10 - Short-Term Borrowings and Credit Arrangements in the NorthWestern Energy Group Annual Report on Form 10-K for the year ended December 31, 2024.

As of June 30, 2025 and 2024, the outstanding balances of our credit facilities were $310.0 million and $213.0 million, respectively. As of July 25, 2025, the availability under our credit facilities was approximately $265.0 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 25, 2025, 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	-	-	Stable
NW Corp				
Fitch[1]	BBB	A-	BBB+	Stable
Moody's	Baa2	A3	Baa2	Stable
S&P[2]	BBB	A-	-	Stable
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, 2025.

	Total	2025	2026	2027	2028	2029	Thereafter
				(in thousands)			
Long-term debt[1]	$ 3,104,660	$ —	$ 105,000	$ —	$ 489,660	$ 33,000	$ 2,477,000
Finance leases	3,731	3,731	0	—	—	—	—
Term Loan Credit Agreement	100,000	—	100,000	—	—	—	—
Estimated pension and other postretirement obligations[2]	45,410	6,410	9,750	9,750	9,750	9,750	N/A
Qualifying facilities liability[3]	198,772	30,180	55,393	56,665	42,400	14,134	—
Supply and capacity contracts[4]	4,140,618	180,066	402,037	357,775	355,608	355,930	2,489,202
Contractual interest payments on debt[5]	1,601,825	78,488	140,009	135,167	138,023	109,651	1,000,487
Commitments for significant capital projects[6]	83,636	48,361	34,998	277	—	—	—
Total Commitments[7]	$ 9,278,652	$ 347,236	$ 847,187	$ 559,634	$ 1,035,441	$ 522,465	$ 5,966,689

(1) Represents cash payments for long-term debt and excludes $15.1 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) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $124 to $130 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $198.8 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $179.3 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 26 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 5.68 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, 2024. As of June 30, 2025, 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, 2024.

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 the Form 10-K for the year ended December 31, 2024 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, 2025, 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 10.1 — Twenty-Second Supplemental Indenture, dated as of May 1, 2025, 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 May 7, 2025, 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 31, 2025

By: /s/ CRYSTAL LAIL

Crystal Lail

Vice President and Chief Financial Officer

Duly Authorized Officer and Principal Financial Officer