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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 OR 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 4, 2026

NorthWestern Energy Group, Inc.

(Exact name of registrant as specified in its charter)

	Delaware		**000-56598**	**93-2020320**
	(State or other jurisdiction of incorporation or organization)		(Commission File Number)	(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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Registrant	Title of each class	Trading Symbol(s)	Name of each exchange on which registered
NorthWestern Energy Group, Inc.	**Common stock**	**NWE**	**Nasdaq Stock Market LLC**

Indicate by check mark whether the registrant is an emerging growth company as defined in as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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.

☐

Item 2.02 Results of Operations and Financial Condition

On November 4, 2026, NorthWestern Energy Group, Inc. d/b/a NorthWestern Energy (Nasdaq: NWE) (the "*Company*"), issued a press release (the "*Press Release*") discussing financial results for the quarter ended September 30, 2026, and affirming earnings guidance for 2026 in the range of $3.68 to $3.83 per diluted share. The Press Release is furnished as Exhibit 99.1 hereto and is incorporated herein by reference.

The information in this Current Report on Form 8-K provided under Item 2.02 shall not be deemed "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that Section. The information provided under Item 2.02 in this Current Report shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such filing.

Item 7.01 Regulation FD Disclosure.

As previously announced and as stated in the Press Release, the Company will host an investor conference call and webcast on November 5, 2026, at 11:00 a.m. Eastern time to review its financial results. During the conference call, Brian Bird, president and chief executive officer, and Crystal Lail, vice president and chief financial officer, will make a slide presentation (the "*Investor Call Presentation*") concerning the Company's financial results.

A live webcast of the investor conference call can be accessed from the Company's website at *www.northwesternenergy.com/earnings-registration*. To listen and view the slideshow presentation, please go to the site at least 15 minutes in advance of the call to register. An archived webcast will be available shortly after the event and remain active for one year.

A copy of the Investor Call Presentation is being furnished pursuant to Regulation FD as Exhibit 99.2 to this Current Report on Form 8-K and is incorporated herein by reference. The information in the presentation shall not be deemed to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Furthermore, the presentation shall not be deemed to be incorporated by reference into the Company's filings under the Securities Act of 1933, as amended, or under the Securities Exchange Act of 1934, as amended, except as set forth with respect thereto in any such filing.

Item 9.01 Financial Statements and Exhibits.

Exhibit No.	Description of Document
99.1*	Press Release, dated November 4, 2026
99.2*	Investor Call Presentation, dated November 5, 2026
104	Cover Page Interactive Data File – the cover page XBRL tags are embedded within the Inline XBRL document

* filed herewith

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 hereunto duly authorized.

NorthWestern Energy Group, Inc.

By: /s/ Timothy P. Olson
Timothy P. Olson
Corporate Secretary

Date: November 5, 2026

NorthWestern Energy Group, Inc.
d/b/a NorthWestern Energy
3010 W. 69th Street
Sioux Falls, SD 57108
www.northwesternenergy.com

FOR IMMEDIATE RELEASE

NorthWestern Energy Reports Third Quarter 2026 Financial Results

- ***Third Quarter 2026 Diluted GAAP EPS of $0.50, compared to $0.62 in 2025.***
- ***Third Quarter 2026 Adjusted Diluted Non-GAAP EPS of $0.58, compared to $0.79 in 2025.***
- ***Affirms 2026 earnings guidance range of $3.68 to $3.83 per diluted share.***
- ***Affirms record $683 million capital plan for 2026 and 4% to 6% long-term EPS and rate base growth rate.***
- ***Announces $0.67 per share quarterly dividend - payable December 1, 2026.***

BUTTE, MT / SIOUX FALLS, SD - November 4, 2026 - NorthWestern Energy Group, Inc. d/b/a NorthWestern Energy (Nasdaq: NWE) reported financial results for the Third Quarter of 2026. Net income for the period was $30.7 million, or $0.50 per diluted share, as compared with net income of $38.2 million, or $0.62 per diluted share, for the same period in 2025. This decrease was primarily due to $6.1 million of net loss associated with our additional ownership interests in Colstrip Units 3 and 4, depreciation expense, and interest expense. These were offset in part by lower non-recoverable Montana electric supply costs, retail volumes, transmission revenue, and lower merger-related costs.

NorthWestern's Third Quarter 2026 non-GAAP net income and diluted earnings per share were $35.6 million and $0.58, respectively, compared to $48.4 million and $0.79 in 2025. See "Adjusted Non-GAAP Earnings" and "Non-GAAP Financial Measures" sections below for more information on these measures.

"The third quarter was a busy and productive one for NorthWestern," said President and CEO Brian Bird. *"We continued to execute on our core business and remain focused on delivering long-term value for our customers, communities, and shareholders. Although the costs associated with our incremental ownership in Colstrip have created a temporary earnings headwind, this strategic decision helps ensure reliable energy for our customers and support economic development in Montana. Looking ahead, we are excited about the prospect of completing our merger with Black Hills and beginning the next chapter for our combined company, subject to final, satisfactory approval from the Montana Public Service Commission which is expected to consider the merger prior to November 12, 2026."*

TRANSACTION UPDATE

On August 18, 2025, we entered into a Merger Agreement with Black Hills Corporation (Black Hills) and a wholly owned subsidiary of Black Hills. The Merger Agreement provides for an all-stock merger of equals between NorthWestern and Black Hills upon the terms and subject to the conditions set forth therein. The new corporate name selected for the resulting parent company of the combined corporate group is Bright Horizon Energy Corporation (Bright Horizon).

In April 2026, shareholders of each company voted to approve the Merger and the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act expired, permitting consummation of the transaction.

In May 2026, the Federal Energy Regulatory Commission (FERC) and the Nebraska Public Service Commission (NPSC) each approved the Merger. In June 2026, the South Dakota Public Utilities Commission (SDPUC) approved the merger.

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

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

During the three and nine months ended September 30, 2026, we have incurred $3.2 million and $9.9 million, respectively, of merger-related costs, which are included in our Administrative and general expenses.

FINANCIAL OUTLOOK

Affirming 2026 Guidance and Long-Term Growth Rates

As noted above, we anticipate completing the merger with Black Hills by year-end 2026. The financial guidance and long-term outlook presented below reflect NorthWestern Energy on a standalone basis. Upon completion of the merger, NorthWestern's standalone guidance and outlook will no longer apply or be indicative of the combined company's expected results.

We are affirming our 2026 non-GAAP earnings guidance of $3.68 - $3.83 per diluted share. This guidance is based upon, but not limited to, the following major assumptions:

- Normal weather in our service territories;
- Excludes costs related to the pending merger with Black Hills;
- Approval of the Power Cost and Credit Adjustment Mechanism (PCCAM) waiver and power prices sufficient to recover operating expense from incremental Avista and Puget Colstrip interests;
- An effective income tax rate of approximately 14 percent to 18 percent; and
- Diluted average shares outstanding of approximately 61.8 million.

We are affirming our long-term diluted earnings per share growth guidance of 4% to 6%, based on our 2024 adjusted diluted non-GAAP EPS baseline of $3.40.

Additionally, we are affirming our $3.2 billion capital investment plan for 2026-2030, which is expected to support rate base growth of 4% to 6% from our 2024 base year of approximately $5.4 billion.

We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt issuances, and future rate increases. In order to fund South Dakota generation investment, equity issuances are expected beginning in 2027.

Dividend Declared

NorthWestern Energy Group's Board of Directors has declared a quarterly common stock dividend of $0.67 per share, payable on December 1, 2026, to shareholders of record as of November 17, 2026. As previously disclosed in NorthWestern's 2025 Annual Report issued in March 2026, this dividend was expected to be payable on December 31, 2026, to shareholders of record on December 15, 2026. The Board revised the record and payment dates in connection with the pending merger transaction and the dividend coordination provisions of the merger agreement.

If the merger receives final, satisfactory regulatory approval and is completed before the November 17, 2026 record date, each share of NorthWestern common stock will be converted into 0.98 shares of Black Hills common stock, with cash paid in lieu of any fractional shares, pursuant to the merger agreement, and Black Hills will be renamed Bright Horizon Energy Corporation. In that event, former NorthWestern shareholders who become shareholders of Bright Horizon as a result of the merger and are shareholders of Bright Horizon on Bright Horizon's November 17, 2026 record date will be eligible to receive the dividend of $0.703 per Bright Horizon share from Bright Horizon that was declared by Black Hills on October 28, 2026. If the merger is completed after the November 17, 2026 record date, NorthWestern shareholders of record on that date will receive the NorthWestern dividend of $0.67 per share payable on December 1, 2026.

NorthWestern remains committed to its targeted dividend payout ratio of 60% to 70% over the long term. This target only reflects NorthWestern on a standalone basis through completion of the pending merger with Black Hills.

Additional information regarding this release can be found in the earnings presentation at *https://www.northwesternenergy.com/investors/earnings*.

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COMPANY UPDATES

Montana Rate Review

In December 2025, the MPSC issued a final order approving our partial electric settlement agreement. The final order also suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC. The ultimate resolution regarding the suspension of the PCCAM cost sharing mechanism will be addressed in a separate PCCAM docket and we anticipate resolution in the first half of 2027. Within this final order, the MPSC disallowed a portion of the capital costs related to the construction of Yellowstone County Generating Station (YCGS). As a result, in the fourth quarter of 2025 we recorded a $30.9 million non-cash charge for the regulatory disallowance.

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

Montana Large New Load Tariff Rule

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

Data Center Development

As previously disclosed, we have signed development agreements with Atlas Power Holdings LLC (Atlas) and Quantica Infrastructure (Quantica) to provide electric supply services for data centers being developed in Montana. The development agreements require us to evaluate the transmission infrastructure and generation resources needed to support their proposed need. Our previously disclosed development agreement with Sabey Data Centers has been terminated. The combined energy service requirement associated with our remaining development agreements is currently expected to be 75 megawatts beginning in late 2027, with growth of up to approximately 1,250 megawatts or more by 2030. We are working with Atlas and Quantica to execute electric service agreements.

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

Colstrip Acquisitions and Requests for Cost Recovery

As previously disclosed, we entered into definitive agreements with Avista and Puget to acquire their respective interests in Colstrip Units 3 and 4 for $0 and completed these acquisitions on January 1, 2026. Accordingly, we are responsible for the associated operating costs beginning on January 1, 2026, which we will not collect through utility base rates until requested in a future Montana rate review. Puget and Avista will remain responsible for their

respective pre-closing share of environmental, asset retirement obligations, and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommissioning and demolition costs associated with the existing facilities that comprise their interests.

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

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

Puget Interests - The 370 megawatts of generation capacity from Colstrip Units 3 and 4 acquired from Puget (Puget Interests) on January 1, 2026, increases our ownership share of the facility to 55 percent and provides an increase in voting share in determining strategic direction and investment decisions at the facility. Unlike the Avista Interests, we do not currently need this capacity to serve existing customers in Montana. As such, the Puget Interests are held by our FERC regulated subsidiary to isolate the costs associated with this acquired interest from our Montana retail customers. While we expect our future opportunity to serve growing customer demand, including large-load customers, may be supported by this resource, in October 2025, we signed a contract to sell the dispatchable capacity and associated energy from the Puget Interests beginning January 1, 2026, through late 2027. Revenues from this agreement are expected to largely offset the estimated $30.0 million of annual incremental operating and maintenance costs associated with the Puget Interests. In addition, in October 2025, we submitted a request to the FERC for approval of cost-based rates for our subsidiary that will own the Puget Interests. In February 2026, the FERC approved both the cost-based rates and the contract rates retroactive to January 1, 2026. In March 2026, two MPSC commissioners, in their individual capacity, filed a motion with the FERC requesting a rehearing that largely reiterated arguments previously rejected by the FERC. The FERC denied this motion by operation of law. In June 2026, the two MPSC commissioners appealed the decision to the Ninth Circuit. The Court granted our intervention. The Court further granted FERC's motion to hold the case in abeyance until December 11, 2026.

Generation Capacity in South Dakota

The Southwest Power Pool (SPP) has recently updated its resource accreditation and planning reserve margin (PRM) requirements in response to growing reliability concerns. As a result, SPP is requiring additional accredited capacity by 2030 to meet the updated PRM targets. In October 2025, we submitted a project with the SPP under their Expedited Resource Adequacy Study program for the construction of a 131 MW natural gas generating facility located in Aberdeen, South Dakota, which has been named the Hub City Energy Park generation project, to meet regional capacity needs by 2030. Anticipated costs for this project are approximately $470.0 million. As of September 30, 2026, we have recorded $42.6 million within Other noncurrent assets on the Condensed Consolidated Balance Sheets for non-refundable milestone payments to secure the turbines that will be used at this facility.

South Dakota Phase In Rate Plan Rider

In June 2026, we filed our annual Phase In Rate Plan Rider (PIRP) update with the SDPUC requesting recovery of costs associated with Aberdeen Generating Station, a 33 megawatt (MW) natural gas fired electric generating facility located in Aberdeen, South Dakota, certain nuclear study costs, and the proposed Hub City Energy Park generation project, a 131 MW natural gas generating facility located in Aberdeen, South Dakota. The filing requests collection of approximately $11.8 million of revenue for the July 2026 through June 2027 period with a requested effective date of September 1, 2026. This represents a $7.4 million increase from the previously approved PIRP revenue amount for the July 2025 through June 2026 period. The filing remains pending before the SDPUC.

Regional Transmission Development Activities

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

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

South Dakota Wildfire Risk Mitigation

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

Financing Update

On August 20, 2026, NW Corp exercised the accordion feature under its existing $425.0 million revolving credit facility to increase the capacity to $500.0 million. On this same day, NorthWestern Energy Group and NWE Public Service exercised the accordion feature under its existing $200.0 million revolving credit facility to increase the capacity to $250.0 million. This increased the base sublimit for NWE Public Service from $150.0 million to $200.0 million. These actions did not affect the maturity date or borrowing rates.

On September 30, 2026, NWE Public Service repaid at maturity $45.0 million of 2.66 percent South Dakota First Mortgage Bonds due on September 30, 2026.

CONSOLIDATED STATEMENT OF INCOME

($ in millions, except per share amounts)	Three Months Ended September 30, 2026	Three Months Ended September 30, 2025	Nine Months Ended September 30, 2026	Nine Months Ended September 30, 2025
Revenues				
Electric	$ 373.6	$ 339.8	$ 1,059.9	$ 954.7
Gas	50.1	47.2	254.0	241.6
Total Revenues	423.8	387.0	1,313.9	1,196.3
Operating expenses				
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	107.3	86.9	342.7	300.4
Operating and maintenance	84.9	64.1	238.5	183.2
Administrative and general	39.5	46.7	128.0	121.8
Property and other taxes	50.5	46.1	151.0	137.5
Depreciation and depletion	67.0	62.8	200.9	187.6
Total Operating Expenses	349.1	306.7	1,061.0	930.5
Operating income	74.6	80.3	253.0	265.8
Interest expense, net	(42.2)	(38.4)	(122.4)	(111.1)
Other income, net	3.0	5.1	10.6	9.1
Income before income taxes	35.4	47.0	141.1	163.8
Income tax expense	(4.7)	(8.8)	(21.9)	(27.4)
Net Income	$ 30.7	$ 38.2	$ 119.2	$ 136.4
Average Common Shares Outstanding	61,518	61,395	61,496	61,372
Basic Earnings per Average Common Share	$ 0.50	$ 0.62	$ 1.94	$ 2.22
Diluted Earnings per Average Common Share	$ 0.50	$ 0.62	$ 1.93	$ 2.22
Dividends Declared per Common Share	$ 0.67	$ 0.66	$ 2.01	$ 1.98

Note: Subtotal variances may exist due to rounding.

RECONCILIATION OF PRIMARY CHANGES DURING THE QUARTER

($ in millions, except per share amounts)	Three Months Ended September 30, 2026 vs. 2025 Pre-tax Income	Income Tax (Expense) Benefit [3]	Net Income	Diluted Earnings Per Share
Third Quarter, 2025	**$ 47.0**	**$ (8.8)**	**$ 38.2**	**$ 0.62**
*Variance in **revenue** and fuel, purchased supply, and direct transmission expense[1] items impacting net income:*				
Electric margin from the acquisition of the Colstrip Puget Interests	5.3	(1.3)	4.0	0.06
Non-recoverable Montana electric supply costs	2.3	(0.6)	1.7	0.03
Electric retail volumes	1.5	(0.4)	1.1	0.02
Electric transmission revenue	1.3	(0.3)	1.0	0.02
Natural gas retail volumes	1.0	(0.3)	0.7	0.01
Rates	(1.2)	0.3	(0.9)	(0.01)
Montana property tax tracker collections	(0.6)	0.2	(0.4)	(0.01)
Production tax credits, offset within income tax expense	(0.5)	0.5	—	—
Natural gas production step down	(0.1)	0.0	(0.1)	0.00
Other	0.1	0.0	0.1	0.00
*Variance in **expense** items[2] impacting net income:*				
Operating, maintenance, and administrative, excluding merger-related costs	(15.3)	3.9	(11.4)	(0.18)
Depreciation	(4.2)	1.1	(3.1)	(0.05)
Interest expense	(3.8)	1.0	(2.8)	(0.05)
Property and other taxes not recoverable within trackers	(2.0)	0.5	(1.5)	(0.02)
Merger-related costs	4.4	0.7	5.1	0.08
Other	0.2	(1.2)	(1.0)	(0.02)
Dilution from higher share count				—
Third Quarter, 2026	**$ 35.4**	**$ (4.7)**	**$ 30.7**	**$ 0.50**
Change in Net Income			**$ (7.5)**	**$ (0.12)**

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

EXPLANATION OF CONSOLIDATED RESULTS

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

Consolidated gross margin for the three months ended September 30, 2026 was $114.1 million as compared with $127.0 million in 2025, a decrease of $12.9 million, or 10.2 percent. This decrease was primarily due to negative margin associated with our additional ownership interests in Colstrip Units 3 and 4 and depreciation expense. These were offset in part by lower non-recoverable Montana electric supply costs, retail volumes, and transmission revenue.

($ in millions)	Three Months Ended September 30,	
Reconciliation of gross margin to utility margin:	**2026**	**2025**
Operating Revenues	$ 423.8	$ 387.0
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	107.3	87.0
Less: Operating and maintenance	84.9	64.1
Less: Property and other taxes	50.5	46.1
Less: Depreciation and depletion	67.0	62.8
Gross Margin	**114.1**	**127.0**
Add back: Operating and maintenance	84.9	64.1
Add back: Property and other taxes	50.5	46.1
Add back: Depreciation and depletion	67.0	62.8
Utility Margin[1]	**$ 316.5**	**$ 300.0**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measures" below.

	Three Months Ended September 30,			
($ in millions)	**2026**	**2025**	**Change**	**% Change**
Utility Margin				
Electric	$ 277.4	$ 262.6	$ 14.8	5.6 %
Natural Gas	39.1	37.4	1.7	4.5
Total Utility Margin[1]	**$ 316.5**	**$ 300.0**	**$ 16.5**	**5.5 %**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measures" below.

Consolidated utility margin for the three months ended September 30, 2026 was $316.5 million as compared with $300.0 million for the same period in 2025, an increase of $16.5 million, or 5.5 percent.

Primary components of the change in utility margin include the following:

($ in millions)	Utility Margin 2026 vs. 2025
Utility Margin Items Impacting Net Income	
Electric margin from the acquisition of the Puget Interests	$ 5.3
Non-recoverable Montana electric supply costs	2.3
Electric retail volumes	1.5
Electric transmission revenue	1.3
Natural gas retail volumes	1.0
Base rates	(1.2)
Montana property tax tracker collections	(0.6)
Natural gas production step down	(0.1)
Other	0.1
Change in Utility Margin Items Impacting Net Income	**9.6**
Utility Margin Items Offset Within Net Income	
Operating expenses recovered in revenue, offset in operating and maintenance expense	5.0
Property and other taxes recovered in revenue, offset in property and other taxes	2.4
Production tax credits, offset in income tax expense	(0.5)
Change in Utility Margin Items Offset Within Net Income	**6.9**
Increase in Consolidated Utility Margin[(1)]	**$ 16.5**

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measures" below.

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

Under the PCCAM, net supply costs higher or lower than the PCCAM base rate (PCCAM Base) (excluding qualifying facility costs) were allocated 90 percent to Montana customers and 10 percent to shareholders. Effective February 1, 2026 the cost sharing mechanism of the PCCAM was suspended on an interim basis pending further review by the MPSC. For the three months ended September 30, 2025, we recorded a decrease in pre-tax earnings of $2.3 million (10 percent of the PCCAM Base cost variance).

	Three Months Ended September 30,			
($ in millions)	2026	2025	Change	% Change
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 84.9	$ 64.1	$ 20.8	32.4
Administrative and general	39.5	46.7	(7.2)	(15.4)
Property and other taxes	50.5	46.1	4.4	9.5
Depreciation and depletion	67.0	62.8	4.2	6.7
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 241.9**	**$ 219.7**	**$ 22.2**	**10.1**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $241.9 million for the three months ended September 30, 2026, as compared with $219.7 million for the three months ended September 30, 2025. Primary components of the change include the following:

($ in millions)	Operating Expenses 2026 vs. 2025
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income	
Electric generation maintenance (including $7.2 million and $4.3 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)	$ 10.5
Depreciation expense due to plant additions and higher depreciation rates	4.2
Labor and benefits[1]	2.8
Property and other taxes not recoverable within trackers (including $1.6 million and $0.3 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)	2.0
Technology implementation and maintenance expenses	1.2
Wildfire mitigation expense, partly offset by higher base revenues	0.5
Uncollectible accounts	0.2
Merger-related costs, including consulting and legal fees	(4.4)
Insurance expense	(0.4)
Other	0.5
Change in Items Impacting Net Income	**17.1**
Operating Expenses Offset Within Net Income	
Operating and maintenance expenses recovered in trackers, offset in revenue	5.0
Property and other taxes recovered in trackers, offset in revenue	2.4
Pension and other postretirement benefits, offset in other income[1]	0.2
Deferred compensation, offset in other income	(2.5)
Change in Items Offset Within Net Income	**5.1**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 22.2**

(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 September 30, 2026 was $74.6 million as compared with $80.3 million in the same period of 2025. This decrease was primarily due to operating losses associated with our additional ownership interests in Colstrip Units 3 and 4 and depreciation expense. These were offset in part by lower non-recoverable Montana electric supply costs, retail volumes, transmission revenue, and lower merger-related costs.

Consolidated interest expense was $42.2 million for the three months ended September 30, 2026 as compared with $38.4 million for the same period of 2025. This increase was due to higher borrowings and interest rates offset in part by higher capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated other income was $3.0 million for the three months ended September 30, 2026 as compared with $5.1 million for the same period of 2025. This decrease was primarily due to a decrease in the value of deferred shares held in trust for deferred compensation offset in part by higher capitalization of AFUDC.

Consolidated income tax expense was $4.7 million for the three months ended September 30, 2026 as compared to $8.8 million for the same period of 2025. Our effective tax rate for the three months ended September 30, 2026 was 13.2% as compared with 18.7% for the same period in 2025.

The following table summarizes the differences between our effective tax rate and the federal statutory rate:

($ in millions)	Three Months Ended September 30, 2026		2025	
	(in dollars)	(in percent)	(in dollars)	(in percent)
Income before income taxes	$ 35.4		$ 47.0	
Income tax calculated at federal statutory rate	7.4	21.0 %	9.9	21.0 %
State income tax, net of federal provision	0.5	1.4	0.1	0.2
Tax Credits				
Production tax credits	(0.9)	(2.5)	(1.3)	(2.8)
Other	—	—	0.2	0.4
Impact of utility ratemaking on income taxes				
Flow-through repairs deductions	(5.6)	(15.8)	(5.2)	(11.1)
Amortization of excess deferred income taxes	(0.8)	(2.3)	(0.4)	(0.8)
AFUDC, net	(0.3)	(0.8)	(0.3)	(0.6)
Plant and depreciation of flow through items	3.9	11.0	3.3	7.0
Changes in Unrecognized Tax Benefits				
Interest and penalties	—	—	0.3	0.6
Nontaxable and nondeductible items				
Merger transaction costs	0.1	0.3	1.9	4.1
Other	0.4	0.9	0.2	0.4
Other	—	—	0.1	0.3
	(2.7)	(7.8)	(1.1)	(2.3)
Income Tax Expense and Effective Tax Rate	$ 4.7	13.2 %	$ 8.8	18.7 %

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

LIQUIDITY AND OTHER CONSIDERATIONS

Liquidity and Capital Resources

As of September 30, 2026, our total net liquidity was approximately $349.5 million, including $6.5 million of cash and cash equivalents and $343.0 million of revolving credit facility availability with no letters of credit outstanding. This compares to total net liquidity one year ago at September 30, 2025 of $262.2 million.

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	
	September 30, 2026	September 30, 2025
Basic computation	61,518,300	61,395,002
Dilutive effect of:		
Performance and restricted share awards[1]	285,233	158,323
Diluted computation	61,803,533	61,553,325

	Nine Months Ended	
	September 30, 2026	September 30, 2025
Basic computation	61,496,216	61,371,962
Dilutive effect of:		
Performance and restricted share awards[1]	240,704	116,597
Diluted computation	61,736,920	61,488,559

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

As of September 30, 2026, there were no shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations, compared to 20,406 shares as of September 30, 2025.

Adjusted Non-GAAP Earnings

We reported GAAP earnings of $0.50 per diluted share for the three months ended September 30, 2026 and $0.62 per diluted share for the same period in 2025. Adjusted Non-GAAP earnings per diluted share for the same periods are $0.58 and $0.79, respectively. A reconciliation of items factored into our Adjusted Non-GAAP diluted earnings are summarized below. The amount below represents a non-GAAP measure that may provide users of this data with additional meaningful information regarding the impact of certain items on our expected earnings. More information on this measure can be found in the "Non-GAAP Financial Measures" section below.

($ in millions, except EPS)

Three Months Ended September 30, 2026	Pre-tax Income	Net[1] Income	Diluted EPS
2026 Reported GAAP	**$35.4**	**$30.7**	**$0.50**
Non-GAAP Adjustments:			
Favorable Weather (Deduct)	(1.1)	(0.8)	(0.01)
Merger-Related Costs[2]	3.2	2.5	0.04
Colstrip Avista Interests[3]	4.3	3.2	0.05
2026 Adj. Non-GAAP	$41.8	$35.6	$0.58

Three Months Ended September 30, 2025	Pre-tax Income	Net[1] Income	Diluted EPS
2025 Reported GAAP	**$47.0**	**$38.2**	**$0.62**
Non-GAAP Adjustments:			
Unfavorable Weather (Addback)	3.5	2.6	0.05
Merger-Related Costs[2]	7.6	7.6	0.12
2025 Adj. Non-GAAP	$58.1	$48.4	$0.79

(1) Income tax rate on reconciling items assumes blended federal plus state effective tax rate of 25.3%.
(2) Certain merger-related costs are not tax-deductible.
(3) Power prices in the Pacific Northwest associated with the designated power sales contracts included within our temporary PCCAM tariff waiver were insufficient to recover the operating expenses associated with the Avista Interests.

Company Hosting Earnings Webinar

NorthWestern will host an investor earnings webinar on Thursday, November 5, 2026, at 11:00 a.m. Eastern time to review its financial results for the three months ended September 30, 2026. To register for the webinar, please visit www.northwesternenergy.com/earnings-registration. Please go to the site at least 15 minutes in advance of the webinar to register. An archived webinar will be available shortly after the event and remain active for one year.

NorthWestern Energy - Delivering a Bright Future

NorthWestern Energy Group, doing business as NorthWestern Energy, provides essential energy infrastructure and valuable services that enrich lives and empower communities while serving as long-term partners to our customers and communities. 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 provide electricity and / or natural gas to approximately 850,300 customers in Montana, South Dakota, Nebraska, and Yellowstone National Park. Upon the completion of the holding company reorganization in 2023, NW Corp became a subsidiary of NorthWestern Energy Group. 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. We have provided service in South Dakota and Nebraska since 1923 and in Montana since 2002.

Non-GAAP Financial Measures

This press release includes financial information prepared in accordance with GAAP, as well as other financial measures, such as Utility Margin, Adjusted Non-GAAP pretax income, Adjusted Non-GAAP net income and Adjusted Non-GAAP Diluted EPS that are considered “non-GAAP financial measures.” 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. A reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure, is included in the press release above.

Management believes 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.

Management also believes the presentation of Adjusted Non-GAAP pre-tax income, Adjusted Non-GAAP net income, and Adjusted Non-GAAP Diluted EPS is more representative of normal earnings than GAAP pre-tax income, net income, and EPS due to the exclusion (or inclusion) of certain impacts that are not reflective of ongoing earnings. The presentation of these non-GAAP measures is intended to supplement investors' understanding of our

financial performance and not to replace other GAAP measures as an indicator of actual operating performance. Our measures may not be comparable to other companies' similarly titled measures.

Special Note Regarding Forward-Looking Statements

This press release contains forward-looking statements within the meaning of the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, including, without limitation, the information under "Adjusted Non-GAAP Earnings." 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, management's examination of historical operating trends, data contained in records, and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

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

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

Additional factors which could affect future results of NorthWestern and Black Hills can be found in NorthWestern Energy's Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K, and Black Hills' Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K, in each case filed with the SEC and available on the SEC's website at http://www.sec.gov. NorthWestern and Black Hills disclaim any obligation and do not intend to update or revise any forward-looking statements contained in this communication, which speak only as of the date hereof, whether as a result of new information, future events or otherwise, except as required by federal securities laws.

Investor Relations Contact:
Travis Meyer (605) 978-2967
travis.meyer@northwestern.com

Media Contact:
Jo Dee Black (866) 622-8081
jodee.black@northwestern.com


NorthWestern Energy
Third Quarter Earnings Webinar
November 5, 2026
8-K Date: November 5, 2026

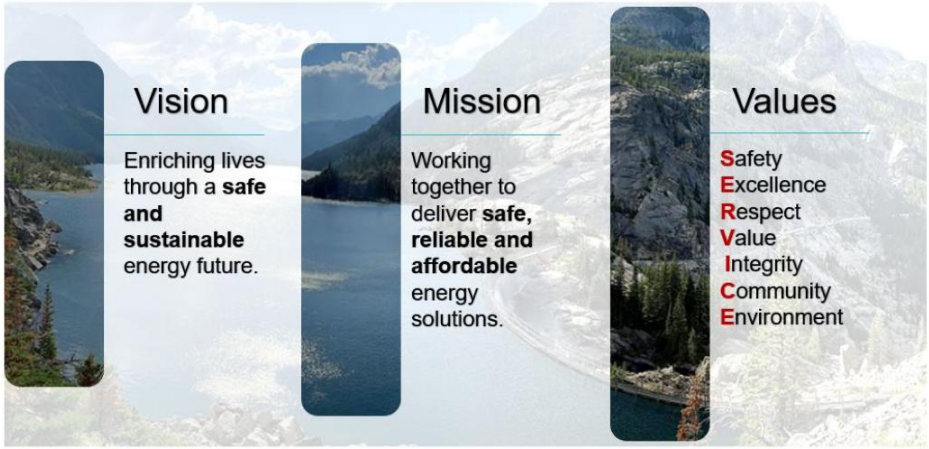
Forward-Looking Statements

Information in this communication, other than statements of historical facts, may constitute forward-looking statements, within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements include, but are not limited to, statements about the benefits of the proposed transaction between NorthWestern and Black Hills, including future financial and operating results (including the anticipated impact of the transaction on NorthWestern's and Black Hills' respective earnings), statements related to the expected timing of the completion of the transaction, the plans, objectives, expectations and intentions of either company or of the combined company following the merger, anticipated future results of either company or of the combined company following the merger, the anticipated benefits and strategic and financial rationale of the merger, including estimated rate bases, investment opportunities, cash flows and capital expenditure rates and other statements that are not historical facts. Forward-looking statements may be identified by terminology such as "may," "will," "should," "targets," "scheduled," "plans," "intends," "goal," "anticipates," "expects," "believes," "forecasts," "outlook," "estimates," "potential," or "continue" or negatives of such terms or other comparable terminology. The forward-looking statements are based on NorthWestern and Black Hills' current expectations, plans and estimates. NorthWestern and Black Hills believe these assumptions to be reasonable, but there is no assurance that they will prove to be accurate.

All forward-looking statements are subject to risks, uncertainties and other factors that may cause the actual results, performance or achievements of NorthWestern or Black Hills to differ materially from any results expressed or implied by such forward-looking statements. Such factors include, among others, (1) the risk of delays in consummating the potential transaction, including as a result of required regulatory and shareholder approvals, which may not be obtained on the expected timeline, or at all, (2) the risk of any event, change or other circumstance that could give rise to the termination of the merger agreement, (3) the risk that required regulatory approvals are subject to conditions not anticipated by NorthWestern and Black Hills, (4) the possibility that any of the anticipated benefits and projected synergies of the potential transaction will not be realized or will not be realized within the expected time period, (5) disruption to the parties' businesses as a result of the announcement and pendency of the transaction, including potential distraction of management from current plans and operations of NorthWestern or Black Hills and the ability of NorthWestern or Black Hills to retain and hire key personnel, (6) reputational risk and the reaction of each company's customers, suppliers, employees or other business partners to the transaction, (7) the possibility that the transaction may be more expensive to complete than anticipated, including as a result of unexpected factors or events, (8) the outcome of any legal or regulatory proceedings that may be instituted against NorthWestern or Black Hills related to the merger agreement or the transaction, (9) the risks associated with third party contracts containing consent and/or other provisions that may be triggered by the proposed transaction, (10) legislative, regulatory, political, market, economic and other conditions, developments and uncertainties affecting NorthWestern's and Black Hills' businesses; (11) the evolving legal, regulatory and tax regimes under which NorthWestern and Black Hills operate; (12) restrictions during the pendency of the proposed transaction that may impact NorthWestern's or Black Hills' ability to pursue certain business opportunities or strategic transactions; and (13) unpredictability and severity of catastrophic events, including, but not limited to, extreme weather, natural disasters, acts of terrorism or outbreak of war or hostilities, as well as NorthWestern's and Black Hills' response to any of the aforementioned factors.

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NorthWestern Energy



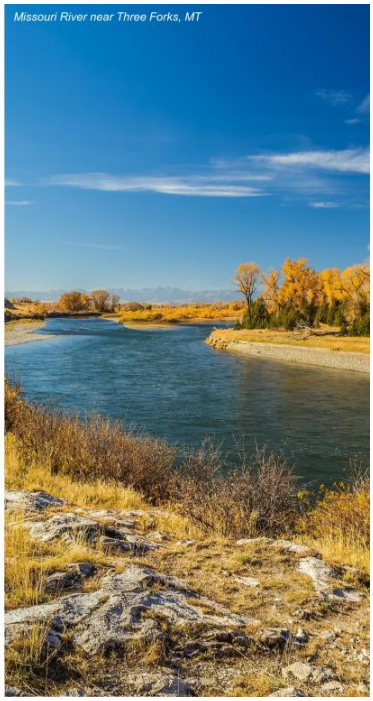
NorthWestern Energy Group, Inc.
dba: NorthWestern Energy
Ticker: NWE (Nasdaq)
www.northwesternenergy.com

Corporate Support Office
3010 West 69th Street
Sioux Falls, SD 57108
(605) 978-2900

Director - Corporate Development & Investor Relations Officer
Travis Meyer
605-978-2967
travis.meyer@northwestern.com

Recent Highlights

- ✓ **Reported GAAP diluted EPS of $0.50**
  - Non-GAAP diluted EPS of $0.58[1]
  - Affirming 2026 earnings guidance range of $3.68 - $3.83[2]
  - Affirming long-term rate base and EPS growth rates targets of 4% - 6%[3]
- ✓ **Dividend Declared:** $0.67 per share payable December 1, 2026
  - This payment date, and November 17 record date, align with Black Hills Corp. dividend dates and is intended to simplify the closing mechanics in the merger.
- ✓ **Merger Progress**
  - Received approvals from the Nebraska PSC, South Dakota PUC, and FERC. Final order expected from the Montana PSC by November 12, 2026. If final, satisfactory approval is received, we anticipate completing the merger with Black Hills Corp. by year-end 2026.


Missouri River near Three Forks, MT

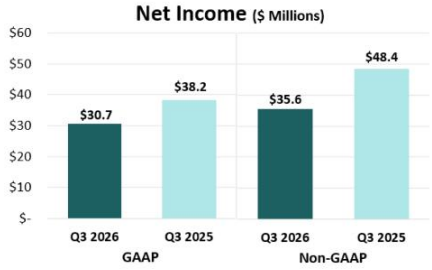
(1) See slides "Third Quarter 2026 Non-GAAP Earnings" and "Non-GAAP Financial Measures" that follow.
(2) Range reflective of NorthWestern on a standalone basis. See "Strong Growth Outlook" slide that follows for major assumptions included in guidance.
(3) Range reflective of NorthWestern on a standalone basis. Based on 2024 Adjusted Diluted Non-GAAP EPS of $3.40 and 2024 estimated rate base of $5.38 billion. See "Non-GAAP Financial Measures" slide in appendix for additional information.

Third Quarter Financial Review

Third Quarter 2026 Financial Results

Third Quarter Net Income vs Prior Period

- GAAP: ↓ $7.5 or (19.6)%
- Non-GAAP[1]: ↓ $12.8 or (26.4)%



Third Quarter EPS vs Prior Period

- GAAP: ↓ $0.12 or (19.4)%
- Non-GAAP[1]: ↓ $0.21 or (26.6)%

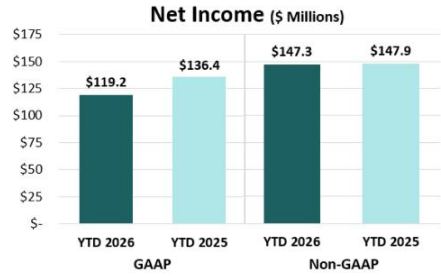


(1) See "Third Quarter 2026 Non-GAAP Earnings" and "Non-GAAP Financial Measures" slides that follow.

Year-to-Date 2026 Financial Results

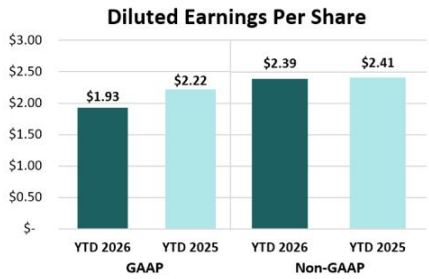
Year-to-Date Net Income vs Prior Period

- GAAP: ↓ $17.2 or (12.6)%
- Non-GAAP[1]: ↓ $0.6 or (0.4)%



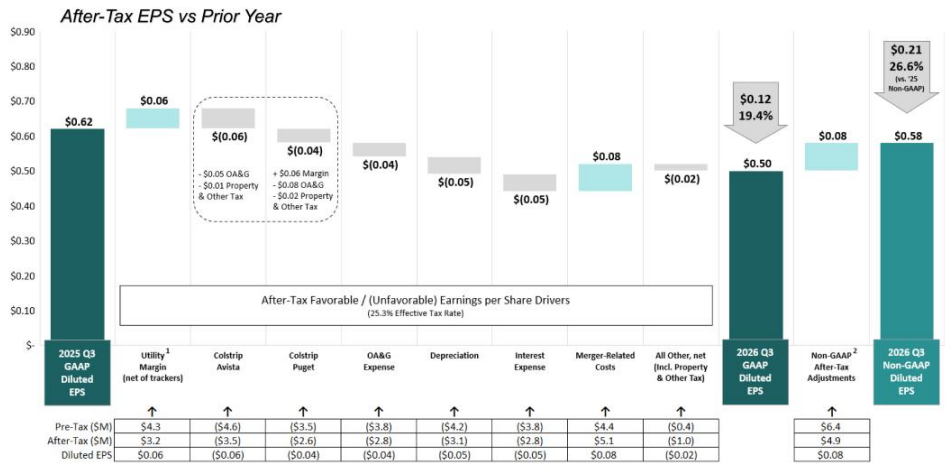
Year-to-Date EPS vs Prior Period

- GAAP: ↓ $0.29 or (13.1)%
- Non-GAAP[1]: ↓ $0.02 or (0.8)%



(1) See "Year-to-Date 2026 Non-GAAP Earnings" and "Non-GAAP Financial Measures" slides that follow.

Third Quarter 2026 Earnings Drivers



Pre-Tax ($M)		$4.3	($4.6)	($3.5)	($3.8)	($4.2)	($3.8)	$4.4	($0.4)	$6.4
After-Tax ($M)		$3.2	($3.5)	($2.6)	($2.8)	($3.1)	($2.8)	$5.1	($1.0)	$4.9
Diluted EPS	$0.62	$0.06	($0.06)	($0.04)	($0.04)	($0.05)	($0.05)	$0.08	($0.02)	$0.08

Key Takeaway

Core utility earnings intact.

Primary Earnings Drivers vs Guidance:

- ▼ Remaining GAAP Colstrip Loss
- ▼ Timing of Operating Expenses

Colstrip represents a $0.10 GAAP EPS headwind as compared to Q3 2025.

Note: Subtotal variances may exist due to rounding.
(1) Utility Margin is a non-GAAP measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.
(2) See "Third Quarter 2026 Non-GAAP Earnings" and "Non-GAAP Financial Measures" slides that follow.

Third Quarter 2026 Non-GAAP Earnings

(in millions)	GAAP	Favorable Weather (Deduct)	Move Pension Expense to OG&A (disaggregated with ASU 2017-07) (1)	Deferred Compensation	Merger-Related Costs (2)	Colstrip Avista Interests (3)	Non-GAAP	Non-GAAP Variance $	Non-GAAP Variance %	Non-GAAP	Merger-Related Costs (2)	Deferred Compensation	Move Pension Expense to OG&A (disaggregated with ASU 2017-07) (1)	Unfavorable Weather (Addback)	GAAP
	Three Months Ended Sept. 30, 2026	Non-GAAP Adjustments					Three Months Ended Sept. 30, 2026	Variance		Three Months Ended Sept. 30, 2025	Non-GAAP Adjustments				Three Months Ended Sept. 30, 2025
	Three Months Ended September 30,														
Revenues	$423.8	(1.1)	-	-	-	4.3	$427.0	$36.5	9.3%	$390.5	-	-	-	3.5	$387.0
Fuel, Supply, & Dir. Tx	107.3	-	-	-	-	-	107.3	20.4	23.5%	86.9	-	-	-	-	86.9
Utility Margin (4)	**316.5**	**(1.1)**	**-**	**-**	**-**	**4.3**	**319.7**	**16.2**	**5.3%**	**303.5**	**-**	**-**	**-**	**3.5**	**300.0**
Op. Expenses															
OG&A Expense	124.4	-	(0.2)	0.7	(3.2)	-	121.7	20.3	20.0%	101.4	(7.6)	(1.8)	-	-	110.8
Prop. & Other Taxes	50.5	-	-	-	-	-	50.5	4.4	9.5%	46.1	-	-	-	-	46.1
Depreciation	67.0	-	-	-	-	-	67.0	4.2	6.7%	62.8	-	-	-	-	62.8
Total Op. Exp.	**241.9**	**-**	**(0.2)**	**0.7**	**(3.2)**	**-**	**239.2**	**28.9**	**13.7%**	**210.3**	**(7.6)**	**(1.8)**	**-**	**-**	**219.7**
Op. Income	**74.6**	**(1.1)**	**0.2**	**(0.7)**	**3.2**	**4.3**	**80.5**	**(12.7)**	**-13.6%**	**93.2**	**7.6**	**1.8**	**-**	**3.5**	**80.3**
Interest Expense	(42.2)	-	-	-	-	-	(42.2)	3.8	9.9%	(38.4)	-	-	-	-	(38.4)
Other Income, net	3.0	-	(0.2)	0.7	-	-	3.5	0.2	6.1%	3.3	-	(1.8)	-	-	5.1
Pre-Tax Income	**35.4**	**(1.1)**	**-**	**-**	**3.2**	**4.3**	**41.8**	**(16.3)**	**-28.1%**	**58.1**	**7.6**	**-**	**-**	**3.5**	**47.0**
Income Tax	(4.7)	0.3	-	-	(0.7)	(1.1)	(6.2)	3.5	36.1%	(9.7)	-	-	-	(0.9)	(8.8)
Net Income	**$30.7**	**(0.8)**	**-**	**-**	**2.5**	**3.2**	**$35.6**	**($12.8)**	**-26.4%**	**$48.4**	**7.6**	**-**	**-**	**2.6**	**$38.2**
ETR	13.2%	25.3%	-	-	21.9%	25.3%	14.8%			16.6%	-	-	-	25.3%	18.7%
Diluted Shares	61.8						61.8	0.2	0.3%	61.6					61.6
Diluted EPS	**$0.50**	(0.01)	-	-	0.04	0.05	**$0.58**	($0.21)	-26.6%	**$0.79**	0.12	-	-	0.05	**$0.62**

(1) As a result of the adoption of Accounting Standard Update 2017-07 in March 2018, pension and other employee benefit expense is now disaggregated on the GAAP income statement with portions now recorded in both OG&A expense and Other (Expense) Income lines. To facilitate better understanding of trends in year-over-year comparisons, the non-GAAP adjustment above re-aggregates the expense in OG&A - as it was historically presented prior to the ASU 2017-07 (with no impact to net income or earnings per share).

(2) Certain merger-related costs are not tax-deductible.

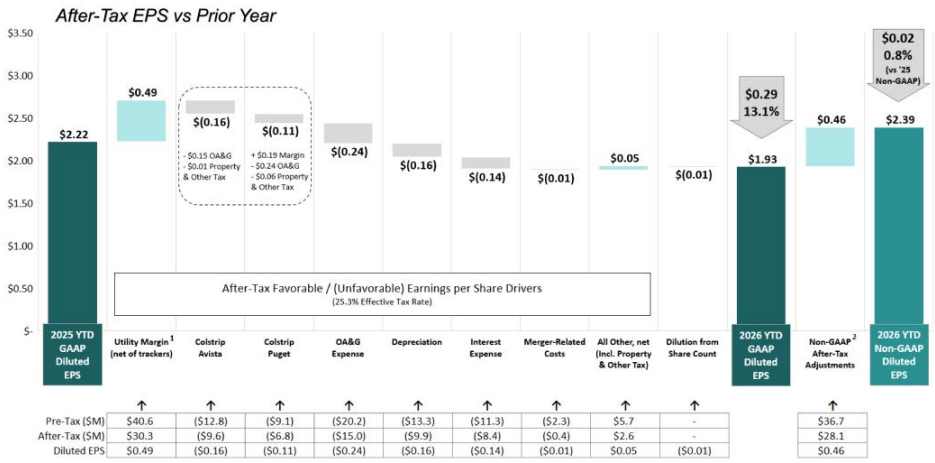
(3) Power prices in the Pacific Northwest associated with the designated power sales contracts included within our temporary PCCAM tariff waiver were insufficient to recover the operating expenses associated with the Avista Interests.

(4) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Note: Subtotal variances may exist due to rounding.

We estimate weather to be a $1.1 million pre-tax benefit as compared to normal, and a $4.6 million benefit as compared to third quarter 2025.

Year-to-Date 2026 Earnings Drivers



Pre-Tax ($M)	$40.6	($12.8)	($9.1)	($20.2)	($13.3)	($11.3)	($2.3)	$5.7	-		$36.7
After-Tax ($M)	$30.3	($9.6)	($6.8)	($15.0)	($9.9)	($8.4)	($0.4)	$2.6	-		$28.1
Diluted EPS	$0.49	($0.16)	($0.11)	($0.24)	($0.16)	($0.14)	($0.01)	$0.05	($0.01)		$0.46

Key Takeaway

Core utility earnings intact.

Primary Earnings Drivers vs Guidance:

- ▼ Remaining GAAP Colstrip Loss
- ▼ Timing of Operating Expenses

Colstrip represents a $0.27 GAAP EPS headwind as compared to year-to-date 2025.

Note: Subtotal variances may exist due to rounding.
(1) Utility Margin is a non-GAAP measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.
(2) See "Year-to-Date 2026 Non-GAAP Earnings" and "Non-GAAP Financial Measures" slides that follow.

Year-to-Date 2026 Non-GAAP Earnings

(in millions)	GAAP	Non-GAAP Adjustments						Non-GAAP	Non-GAAP Variance		Non-GAAP	Non-GAAP Adjustments					GAAP
	Nine Months Ended Sept. 30, 2026	Unfavorable Weather (Addback)	Move Pension Expense to OG&A (disaggregated with ASU 2017-07) (1)	Deferred Compensation	Merger-Related Costs (2)	Remove Jan/Feb PCCAM Expense Following MPSC Suspension of 90/10 Sharing	Colstrip Avista Interests (3)	Nine Months Ended Sept. 30, 2026	Variance $	Variance %	Nine Months Ended Sept. 30, 2025	Merger-Related Costs (2)	Community Renewable Energy Project Benefits (not tax deductible)	Deferred Compensation	Move Pension Expense to OG&A (disaggregated with ASU 2017-07) (1)	Unfavorable Weather (Addback)	Nine Months Ended Sept. 30, 2025
	Nine Months Ended September 30,																
Revenues	$1,313.9	14.2	-	-	-	0.7	11.9	$1,340.7	$140.6	11.7%	1,200.1	-	-	-	-	3.8	$1,196.3
Fuel, Supply, & Dir. Tx	$342.7	-	-	-	-	-	-	342.7	42.3	14.1%	300.4	-	-	-	-	-	300.4
Utility Margin[4]	**971.3**	**14.2**	**-**	**-**	**-**	**0.7**	**11.9**	**998.1**	**98.4**	**10.9%**	**899.7**	**-**	**-**	**-**	**-**	**3.8**	**895.9**
Op. Expenses																	
OG&A Expense	$366.5	-	(0.1)	(1.1)	(9.9)	-	-	355.3	60.1	20.4%	295.2	(7.6)	-	(1.6)	(0.6)	-	305.0
Prop. & Other Taxes	$151.0	-	-	-	-	-	-	151.0	13.5	9.8%	137.5	-	-	-	-	-	137.5
Depreciation	$200.9	-	-	-	-	-	-	200.9	13.3	7.1%	187.6	-	-	-	-	-	187.6
Total Op. Exp.	**718.4**	**-**	**(0.1)**	**(1.1)**	**(9.9)**	**-**	**-**	**707.3**	**87.0**	**14.0%**	**620.3**	**(7.6)**	**-**	**(1.6)**	**(0.6)**	**-**	**630.1**
Op. Income	**253.0**	**14.2**	**0.1**	**1.1**	**9.9**	**0.7**	**11.9**	**290.9**	**11.5**	**4.1%**	**279.4**	**7.6**	**-**	**1.6**	**0.6**	**3.8**	**265.8**
Interest Expense	($122.4)	-	-	-	-	-	-	(122.4)	(11.3)	-10.2%	(111.1)	-	-	-	-	-	(111.1)
Other Income, net	$10.6	-	(0.1)	(1.1)	-	-	-	9.4	1.5	19.0%	7.9	-	1.0	(1.6)	(0.6)	-	9.1
Pre-Tax Income	**141.1**	**14.2**	**-**	**-**	**9.9**	**0.7**	**11.9**	**177.8**	**1.6**	**0.9%**	**176.2**	**7.6**	**1.0**	**-**	**-**	**3.8**	**163.8**
Income Tax	($21.9)	(3.6)	-	-	(1.9)	(0.2)	(3.0)	(30.6)	(2.3)	-8.1%	(28.3)	-	-	-	-	(0.9)	(27.4)
Net Income	**$119.2**	**10.7**	**-**	**-**	**8.0**	**0.5**	**8.9**	**$147.3**	**($0.6)**	**-0.4%**	**$147.9**	**7.6**	**1.0**	**-**	**-**	**2.9**	**$136.4**
ETR	15.5%	25.3%	-	-	19.2%	25.3%	25.3%	17.2%			16.0%	0.0%	0.0%	-	-	23.3%	16.7%
Diluted Shares	61.7							61.7	0.2	0.3%	61.5						61.5
Diluted EPS	**$1.93**	0.17	-	-	0.13	0.01	0.15	**$2.39**	($0.02)	-0.8%	**2.41**	0.12	0.02	-	-	0.05	**$2.22**

(1) As a result of the adoption of Accounting Standard Update 2017-07 in March 2018, pension and other employee benefit expense is now disaggregated on the GAAP income statement with portions now recorded in both OG&A expense and Other (Expense) Income lines. To facilitate better understanding of trends in year-over-year comparisons, the non-GAAP adjustment above re-aggregates the expense in OG&A - as it was historically presented prior to the ASU 2017-07 (with no impact to net income or earnings per share).

(2) Certain merger-related costs are not tax-deductible.

(3) Power prices in the Pacific Northwest associated with the designated power sales contracts included within our temporary PCCAM tariff waiver were insufficient to recover the operating expenses associated with the Avista Interests.

(4) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Note: Subtotal variances may exist due to rounding.

We estimate weather to be a $14.2 million pre-tax detriment as compared to normal, and a $10.4 million detriment as compared to the nine months ending third quarter 2025.

Strong Growth Outlook

Affirming 2026 Non-GAAP EPS Guidance of $3.68 - $3.83 per diluted share

- ✓ **Affirming long-term growth rate from 2024 base[1]**
  - **EPS growth of 4% to 6%**
  - **Rate base growth of 4% to 6%**
  - Continued focus on closing the gap between earned & authorized returns
- ✓ **$3.2 billion 5-year capital plan** including investment for generation development in South Dakota
- ✓ **Cash from operations and debt to fund base capital plan.** Equity issuances expected beginning in 2027 to fund South Dakota generation investment
- ✓ **Targeting FFO / Debt > 14%**

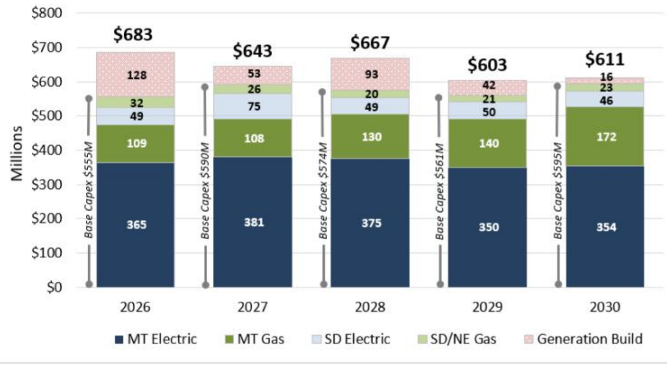


The 2026 Non-GAAP EPS guidance range is based upon, but not limited to, the following major assumptions:

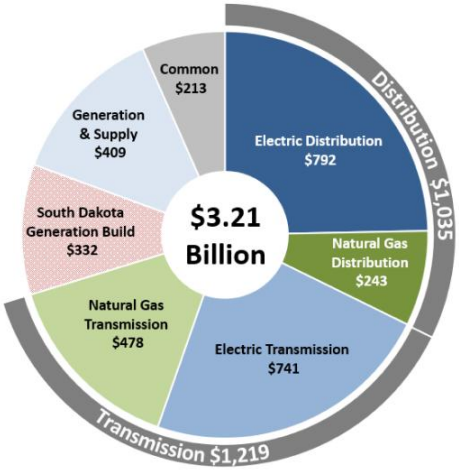
- Normal weather in our service territories;
- Excludes costs related to the pending merger with Black Hills Corp.;
- Approval of PCCAM waiver and power prices sufficient to recover operating expense from incremental Avista and Puget Colstrip interests;
- An effective income tax rate of approximately 14%-18%; and
- Diluted average shares outstanding of approximately 61.8 million.

(1) Based on 2024 Adjusted Diluted Non-GAAP EPS of $3.40 and 2024 estimated rate base of $5.38 billion. See "Non-GAAP Financial Measures" slide in appendix for additional information.

Regulated Utility Five-Year Capital Plan (millions)



$ Millions	***2026***	***2027***	***2028***	***2029***	***2030***	***5yr Total***
Electric	$542	$509	$517	$442	$416	$2,426
Natural Gas	$141	$134	$150	$161	$195	$781
Total Capital Forecast	**$683**	**$643**	**$667**	**$603**	**$611**	**$3,207**



Highly diversified, executable, and low-risk critical capital investment plan.

Business Updates

Merger with Black Hills Benefits Stakeholders

Increases Scale Position and Growth

Increases the combined company target EPS growth rate to 5-7%, supported by the doubling of each company's rate base to total of ~$12 billion with significant growth opportunities

Expands Investment Opportunity

Leverages enhanced resources to make strategic investments that foster economic development, including addressing the growing demand for energy, including from data centers



Strengthens Balance Sheet

Strong and predictable cash flows support a customer-focused capital investment program while producing high-quality, investment-grade credit metrics

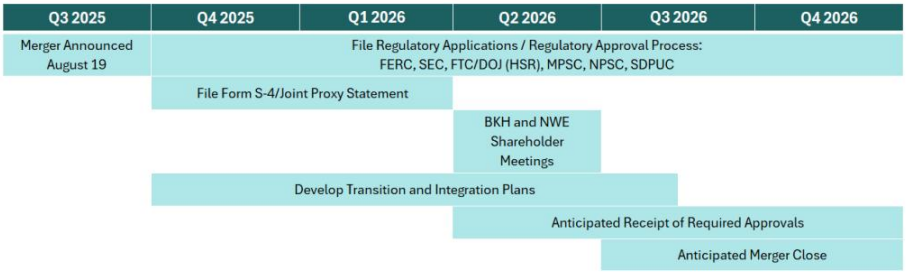
Enhances Business Diversity

Delivering energy to more than 2.2 million customers across multiple contiguous jurisdictions, served by a highly skilled workforce focused on safety and reliability

Strategic combination represents a highly attractive value creation opportunity for both companies.

For more information, see www.blackhillsnorthwesternbettertogether.com

Merger with Black Hills Timeline



- ✓ Filed joint applications for approval in Montana, Nebraska, and South Dakota in Q4 2025
  - ✓ Nebraska hearing held April 7, 2026; unanimous approval of settlements received May 19, 2026
  - ✓ South Dakota hearing held and unanimous approval of settlements received June 24, 2026
  - ✓ Settlements reached with certain key intervenors in Montana
  - ○ Montana hearing concluded May 15, 2026; final briefs submitted July 13, 2026; final order expected by November 12, 2026
- ✓ Filed joint application with FERC on December 22, 2025
  - ✓ FERC approval received May 29, 2026
- ✓ Filed S-4/Joint Proxy Statement on January 30, 2026
  - ✓ Shareholder approvals received by both companies on April 2, 2026
- ✓ Filed Hart-Scott-Rodino on March 20, 2026
  - ✓ 30-day waiting period expired April 20, 2026, satisfying a U.S. antitrust condition to closing

Final remaining approval

Data Center Process (Montana & South Dakota)



Data Center Request & Assessment

- Load & Location
- Viability Assessment
- Supply Potential / Southwest Power Pool Screening
- Customer/Developer Required Timing
- High-level Cost Estimates

Queue Count: 16

Development Agreement

- Deposit Funds Studies (Montana: System Impact Study & Facility Study, South Dakota: Southwest Power Pool Delivery Point Network Study)

Queue Count: 2

Energy Service Agreement (ESA)

- Regulatory Approvals (as needed)
- Contract Signing
- Business Development Handoff

Queue Count: 0

Construction

- Project Management Assignment
- Construction Kick-Off
- Supply Development
- Generation Build Process

Queue Count: 0

Large-Load Customers

✓ **Montana**
- Expected to be served by overall utility portfolio, which is long capacity beginning in 2026
- Diversified and highly carbon-free generating portfolio
- Submitted a Large New Load tariff rule proposal with the MPSC in March 2026

✓ **South Dakota**
- Significant indications of interest
- South Dakota PUC has an established process for large-load customers with a deviated rate tariff

Any large-load customers requiring new generation in Montana or South Dakota would be expected to provide credit support during construction.

Montana Large-Load Opportunities

✓ **Announced: December 19, 2024**
- Company: Atlas Power
- Study Load: 75 MW ramping to 150 MW
- Targeted Start Date: Late 2027
- Agreement Status: **Development Agreement**

✓ **Announced: July 30, 2025**
- Company: Quantica Infrastructure
- Study Load: 25 MW ramping to 1,100 MW
- Targeted Start Date: Early 2029
- Agreement Status: **Development Agreement**

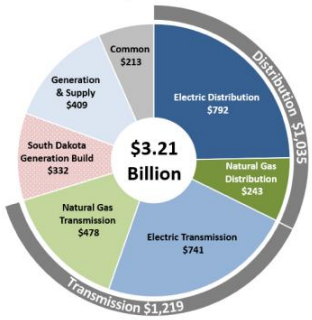
The NorthWestern Value Proposition

Approximately 4% Dividend Yield

\+

Base Capital Plan:
4% to 6% EPS Growth

2026-2030 Capital Investment
($ Millions)



=

8% to 10% Total Return

\+

Incremental Opportunities:
> 6% EPS Growth

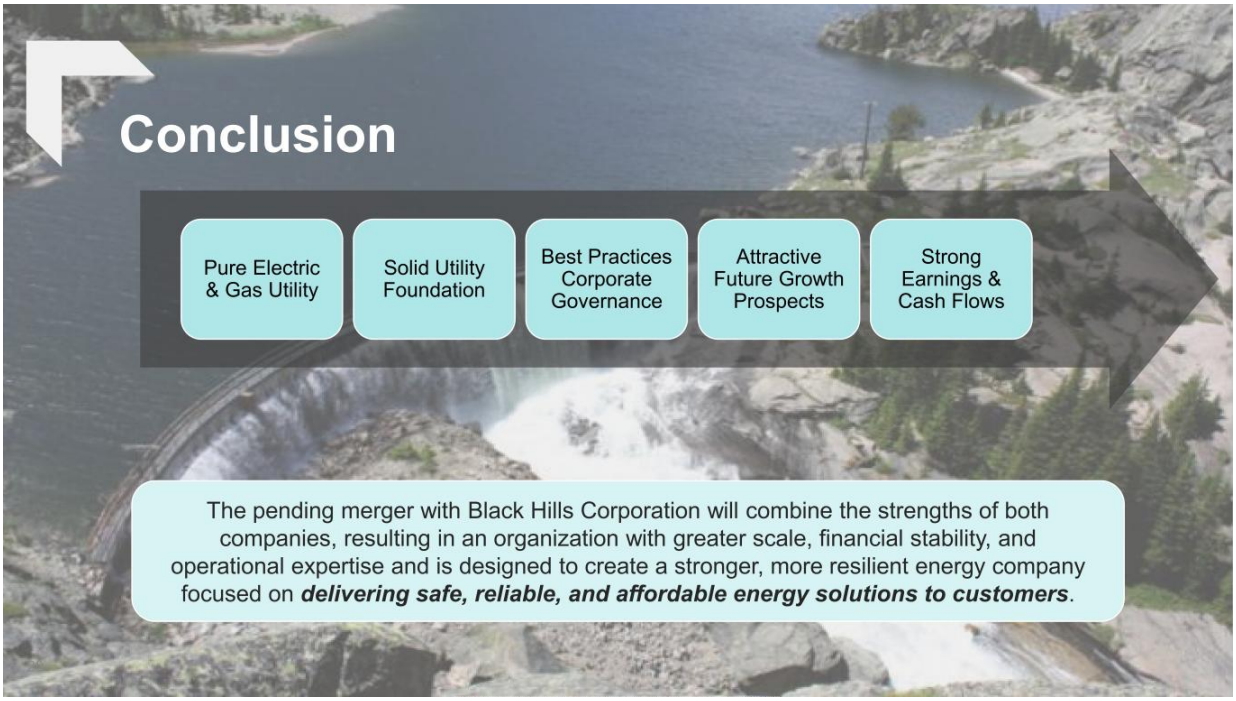
- ✓ **Data centers & new large-load opportunities**
- ✓ **FERC Regional Transmission**
- ✓ **Incremental generating capacity**
  (subject to successful resource procurement bids)

=

> 10% Total Return

$3.21 billion
of highly diversified, executable and low-risk critical capital investment forecasted over the next five years.

This investment is expected to drive annualized earnings and rate base growth of approximately 4% - 6%.


Conclusion
Pure Electric & Gas Utility
Solid Utility Foundation
Best Practices Corporate Governance
Attractive Future Growth Prospects
Strong Earnings & Cash Flows
The pending merger with Black Hills Corporation will combine the strengths of both companies, resulting in an organization with greater scale, financial stability, and operational expertise and is designed to create a stronger, more resilient energy company focused on ***delivering safe, reliable, and affordable energy solutions to customers***.

Appendix:

Appendix

Colstrip Transaction Overview

	Avista	Puget
Announcement:	**January 2023**	**July 2024**
Effective Date:	**December 31, 2025**	**December 31, 2025**
Capacity:	**222 MW** (111 MW each of units 3 & 4)	**370 MW** (185 MW each of units 3 & 4)
Acquisition Price:	**$0.0**	**$0.0**
Status Update:	Filed a temporary PCCAM tariff waiver request with the MPSC in August 2025 that would provide a near-term cost-recovery mechanism to offset a portion of the ~$18.0 million of incremental annual operating costs resulting from the transfer. The waiver was temporarily granted in January 2026.	Signed contract in October 2025 to sell the dispatchable capacity and associated energy through late 2027. Revenue from the contract is expected to largely offset the ~$30 million of incremental annual operating costs resulting from the transfer. Filed with FERC for cost-based rates in October 2025, with approval received in February 2026 retroactive to January 1, 2026.

NorthWestern's acquisition of Avista and Puget's 592 MW of additional Colstrip capacity:

- Avista interests advance our regulated portfolio to resource adequacy and increase facility ownership from 15% to 30%
- Puget interests move ownership from 30% to 55% which provides the ability to determine strategic direction and investment decisions at the facility
- Combined interests support the integration of large-load customers, delivering substantial benefits to our customers, communities, and investors

Avista and Puget Sound will remain responsible for their respective pre-closing share of environmental, asset retirement obligations, 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

Appendix

Financial Impact of Incremental Colstrip Ownership

	Three Months Ended September 30, 2026								
	GAAP Impact			Non-GAAP Addback			Remaining Impact		
	Avista	Puget	Total	Avista	Puget	Total	Avista	Puget	Total
Utility Margin[1]	$ -	$ 5.3	$ 5.3	$ 4.3	$ -	$ 4.3	$ -	$ 5.3	$ 5.3
Operating Expense	4.3	7.2	11.5	-	-	-	-	7.2	7.2
Property Tax Expense	0.3	1.6	1.9	-	-	-	0.3	1.6	1.9
Pre-Tax Income	$ (4.6)	$ (3.5)	$ (8.1)	$ 4.3	$ -	$ 4.3	$ (0.3)	$ (3.5)	$ (3.8)
Income Tax Expense (Benefit)	1.1	0.9	2.0	(1.1)	-	(1.1)	0.0	0.9	0.9
Net Income	$ (3.5)	$ (2.6)	$ (6.1)	$ 3.2	$ -	$ 3.2	$ (0.3)	$ (2.6)	$ (2.9)
Diluted EPS	$ (0.06)	$ (0.04)	$ (0.10)	$ 0.05	$ -	$ 0.05	$ (0.01)	$ (0.04)	$ (0.05)

	Nine Months Ended September 30, 2026								
	GAAP Impact			Non-GAAP Addback			Remaining Impact		
	Avista	Puget	Total	Avista	Puget	Total	Avista	Puget	Total
Utility Margin[1]	$ -	$ 15.5	$ 15.5	$ 11.9	$ -	$ 11.9	$ -	$ 15.5	$ 15.5
Operating Expense	11.9	19.9	31.8	-	-	-	-	19.9	19.9
Property Tax Expense	0.9	4.7	5.6	-	-	-	0.9	4.7	5.6
Pre-Tax Income	$ (12.8)	$ (9.1)	$ (21.9)	$ 11.9	$ -	$ 11.9	$ (0.9)	$ (9.1)	$ (10.0)
Income Tax Expense (Benefit)	3.2	2.3	5.5	(3.0)	-	(3.0)	0.2	2.3	2.5
Net Income	$ (9.6)	$ (6.8)	$ (16.4)	$ 8.9	$ -	$ 8.9	$ (0.7)	$ (6.8)	$ (7.5)
Diluted EPS	$ (0.16)	$ (0.11)	$ (0.27)	$ 0.15	$ -	$ 0.15	$ (0.01)	$ (0.11)	$ (0.12)

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Appendix

Rate Base & Authorized Return Summary

Estimate as of 12/31/2025

Jurisdiction and Service	Implementation Date	Authorized Rate Base (millions)	Year-End Estimated Rate Base (millions)	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Montana electric delivery and production[1]	February 2026	$ 3,176.2	$ 3,425.6	7.00%	9.65%	47.84%
Montana - Colstrip Unit 4	February 2026	$ 256.7	$ 256.0	8.25%	10.00%	50.00%
Montana natural gas delivery and production[2]	February 2026	$ 757.3	$ 886.6	6.97%	9.60%	47.84%
Montana natural gas delivery - Great Falls Gas	October 2018[3]	$ 17.5	$ 27.4	6.91%	9.20%	50.97%
Total Montana[4]		$ 4,207.7	$ 4,595.6			
South Dakota electric[5]	January 2024	$ 791.8	$ 795.0	6.81%	n/a	n/a
South Dakota natural gas[5]	December 2024	$ 96.2	$ 124.4	6.91%	n/a	n/a
Total South Dakota		$ 888.0	$ 919.4			
Nebraska natural gas[5]	July 2025	$ 46.0	$ 54.7	7.09%	9.55%	n/a
Total NorthWestern Energy		$ 5,141.7	$ 5,569.7			

(1) The revenue requirement associated with the FERC regulated portion of Montana electric transmission and ancillary services are included as revenue credits to our MPSC jurisdictional customers. Therefore, we do not separately reflect FERC authorized rate base or authorized returns.

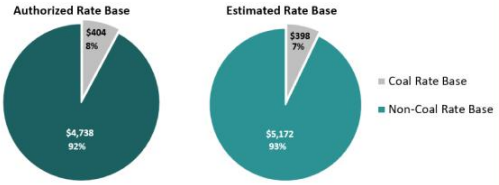
(2) The Montana gas revenue requirement includes a step-down which approximates annual depletion of our natural gas production assets included in rate base.

(3) This jurisdiction was acquired in 2025 as part of the acquisition of Energy West Operations.

(4) This table excludes insignificant jurisdictions for Montana propane delivery, Havre Pipeline Company, and Cut Bank Gas natural gas delivery.

(5) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.

Coal Generation Rate Base as a percentage of Total Rate Base



Revenue from coal generation is not easily identifiable due to the use of bundled rates in South Dakota and other rate design and accounting considerations. However, NorthWestern is a fully regulated utility company for which rate base is the primary driver of earnings. The data to the left illustrates that NorthWestern only derives approximately 7-8% of earnings from its jointly owned coal generation rate base.

Third Quarter Appendix

Appendix

Third Quarter 2026 Financial Results

($ in millions, except per share amounts)	Three Months Ended September 30,			
	2026	2025	Variance	% Variance
Operating Revenues	$423.8	$387.0	$36.8	9.5%
Fuel, Purchased Supply, & Direct Transmission Expense (exclusive of depreciation and depletion)	107.3	86.9	20.4	23.5%
Utility Margin[1]	**316.5**	**300.0**	**16.5**	**5.5%**
Operating Expenses				
Operating and Maintenance	84.9	64.1	20.8	32.4%
Administrative and General	39.5	46.7	(7.2)	(15.4%)
Property and Other Taxes	50.5	46.1	4.4	9.5%
Depreciation and Depletion	67.0	62.8	4.2	6.7%
Total Operating Expenses	**241.9**	**219.7**	**22.2**	**10.1%**
Operating Income	**74.6**	**80.3**	**(5.7)**	**(7.1%)**
Interest Expense, net	(42.2)	(38.4)	3.8	9.9%
Other Income, net	3.0	5.1	(2.1)	(41.2%)
Income Before Income Taxes	**35.4**	**47.0**	**(11.6)**	**(24.7%)**
Income Tax Expense	(4.7)	(8.8)	(4.1)	(46.6%)
Net Income	**$30.7**	**$38.2**	**($7.5)**	**(19.6%)**
Effective Tax Rate	13.2%	18.7%	-5.5%	
Diluted Shares Outstanding	61.8	61.6	0.2	0.3%
Diluted Earnings per Share	$0.50	$0.62	($0.12)	(19.4%)
Dividends Paid per Common Share	$0.67	$0.66	$0.01	1.5%

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Note: Subtotal variances may exist due to rounding.

Appendix

Utility Margin (Q3)

($ in millions)

	Three Months Ended September 30,			
	2026	2025	Variance	
Electric	$ 277.4	$ 262.6	$ 14.8	5.6%
Natural Gas	39.1	37.4	1.7	4.5%
Total Utility Margin[1]	**$ 316.5**	**$ 300.0**	**$ 16.5**	**5.5%**

Increase in utility margin due to the following factors:

$ 5.3	Electric margin from the acquisition of the Puget Interests
2.3	Non-recoverable Montana electric supply costs
1.5	Electric retail volumes
1.3	Electric transmission revenue
1.0	Natural gas retail volumes
(1.2)	Base rates
(0.6)	Montana property tax tracker collections
(0.1)	Natural gas production step down
0.1	Other
$ 9.6	**Change in Utility Margin Impacting Net Income**
$ 5.0	Operating expenses recovered in revenue, offset in operating and maintenance expense
2.4	Property and other taxes recovered in revenue, offset in property and other taxes
(0.5)	Production tax credits, offset in income tax expense
$ 6.9	**Change in Utility Margin Offset Within Net Income**
$ 16.5	**Increase in Consolidated Utility Margin**

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Note: Subtotal variances may exist due to rounding.

Appendix

Operating Expenses (Q3)

($ in millions)

	Three Months Ended September 30,			
	2026	2025	Variance	
Operating & maintenance	$ 84.9	$ 64.1	$ 20.8	32.4%
Administrative & general	39.5	46.7	(7.2)	(15.4%)
Property & other taxes	50.5	46.1	4.4	9.5%
Depreciation & depletion	67.0	62.8	4.2	6.7%
Total Operating Expenses*	**$ 241.9**	**$ 219.7**	**$ 22.2**	**10.1%**

Increase in operating expenses due to the following factors:

$ 10.5	Electric generation maintenance (Including $7.2 million and $4.3 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)
4.2	Depreciation expense due to plant additions and higher depreciation rates
2.8	Labor and benefits(1)
2.0	Property and other taxes not recoverable within trackers (including $1.6 million and $0.3 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)
1.2	Technology implementation and maintenance expenses
0.5	Wildfire mitigation expense, partly offset by higher base revenues
0.2	Uncollectible accounts
(4.4)	Merger-related costs, including consulting and legal fees
(0.4)	Insurance expense
0.5	Other
$ 17.1	**Change in Operating Expense Items Impacting Net Income**
$ 5.0	Operating and maintenance expenses recovered in trackers, offset in revenue
2.4	Property and other taxes recovered in trackers, offset in revenue
0.2	Pension and other postretirement benefits, offset in other income(1)
(2.5)	Deferred compensation, offset in other income
$ 5.1	**Change in Operating Expense Items Offset Within Net Income**
$ 22.2	**Increase in Operating Expenses***

**Excluding fuel, purchased supply, and direct transmission expense.*

(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.

Appendix

Operating to Net Income (Q3)

($ in millions)

	Three Months Ended September 30,			
	2026	2025	Variance	
Operating Income	**$ 74.6**	**$ 80.3**	**($5.7)**	**(7.1%)**
Interest Expense, net	(42.2)	(38.4)	3.8	9.9%
Other Income, net	3.0	5.1	(2.1)	(41.2%)
Income Before Income Taxes	**35.4**	**47.0**	**(11.6)**	**(24.7%)**
Income Tax Expense	(4.7)	(8.8)	(4.1)	(46.6%)
Net Income	**$ 30.7**	**$ 38.2**	**($7.5)**	**(19.6%)**

Note: Subtotal variances may exist due to rounding.

Appendix

Tax Reconciliation (Q3)

($ in millions)	Three Months Ended September 30,				
	2026		2025		Variance
Income Before Income Taxes	**$ 35.4**		**$ 47.0**		**($11.6)**
Income tax calculated at federal statutory rate	7.4	21.0%	9.9	21.0%	(2.5)
State income tax, net of federal provision	0.5	1.4	0.1	0.2	0.4
Tax Credits					
Production tax credits	(0.9)	(2.5)	(1.3)	(2.8)	0.4
Other	-	-	0.2	0.4	(0.2)
Impact of utility ratemaking on income taxes					
Flow-through repairs deductions	(5.6)	(15.8)	(5.2)	(11.1)	(0.4)
Amortization of excess deferred income taxes	(0.8)	(2.3)	(0.4)	(0.8)	(0.4)
AFUDC, net	(0.3)	(0.8)	(0.3)	(0.6)	-
Plant and depreciation of flow-through items	3.9	11.0	3.3	7.0	0.6
Changes in Unrecognized Tax Benefits					
Interest and penalties	-	-	0.3	0.6	(0.3)
Nontaxable and nondeductible items					
Merger transaction costs	0.1	0.3	1.9	4.1	(1.8)
Other	0.4	0.9	0.2	0.4	0.2
Other	-	-	0.1	0.3	(0.1)
	(2.7)	(7.8%)	(1.1)	(2.3%)	(1.6)
Income Tax Expense and Effective Tax Rate	**$ 4.7**	**13.2%**	**$ 8.8**	**18.7%**	**$ (4.1)**

Appendix

Segment Results (Q3)

($ in thousands)

Three Months Ended September 30, 2026	Electric	Gas	Total
Operating revenues	$ 373,624	$ 50,136	$ 423,760
Fuel, purchased supply, & direct transmission*	96,270	11,010	107,280
Utility margin [1]	277,354	39,126	316,480
Operating, general, and administrative	95,381	25,598	120,979
Property & other taxes	39,491	10,958	50,449
Depreciation & depletion	55,596	11,453	67,049
Operating income	86,886	(8,883)	78,003
Interest expense, net	(32,387)	(8,498)	(40,885)
Other income, net	2,286	934	3,220
Income tax (expense) benefit	(10,961)	2,891	(8,070)
Segment net income (loss)	$ 45,824	$ (13,556)	$ 32,268
Reconciliation to consolidated net income			
Other, net [2]			(1,526)
Consolidated net income			$ 30,742

Three Months Ended September 30, 2025	Electric	Gas	Total
Operating revenues	$ 339,751	$ 47,201	$ 386,952
Fuel, purchased supply, & direct transmission*	77,179	9,754	86,933
Utility margin [1]	262,572	37,447	300,019
Operating, general, and administrative	76,522	26,429	102,951
Property & other taxes	35,412	10,652	46,064
Depreciation & depletion	52,338	10,495	62,833
Operating income	98,300	(10,129)	88,171
Interest expense, net	(28,935)	(7,939)	(36,874)
Other income, net	3,275	1,291	4,566
Income tax (expense) benefit	(11,363)	2,124	(9,239)
Segment net income (loss)	$ 61,277	$ (14,653)	$ 46,624
Reconciliation to consolidated net income			
Other, net [2]			(8,391)
Consolidated net income			$ 38,233

**Direct transmission expense excludes depreciation and depletion.*

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

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

Appendix

Electric Segment (Q3)

	Three Months Ended September 30,							
	Revenues		Change		Megawatt Hours (MWH)		Average Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 120,755	$ 110,788	$ 9,967	9.0 %	690	686	338,279	334,448
South Dakota	22,988	21,358	1,630	7.6 %	158	151	52,059	51,768
Residential	**143,743**	**132,146**	**11,597**	**8.8 %**	**848**	**837**	**390,338**	**386,216**
Montana	127,416	116,911	10,505	9.0 %	838	838	77,847	77,154
South Dakota	34,978	32,490	2,488	7.7 %	287	277	13,294	13,223
Commercial	**162,394**	**149,401**	**12,993**	**8.7 %**	**1,125**	**1,115**	**91,141**	**90,377**
Industrial	12,068	12,070	(2)	(0.0) %	689	695	81	81
Other	15,467	14,393	1,074	7.5 %	72	79	30,310	30,219
Total Retail Electric	**333,672**	**308,010**	**25,662**	**8.3 %**	**2,734**	**2,726**	**511,870**	**506,893**
Regulatory amortization	(23,368)	980	(24,348)	(2,484.5) %				
Transmission	29,251	27,923	1,328	4.8 %				
Wholesale and other	34,069	2,838	31,231	1,100.5 %				
Total Revenues	**373,624**	**339,751**	**33,873**	**10.0 %**				
Total fuel, purchased supply, & direct transmission expense*	96,270	77,179	19,091	24.7 %				
Utility Margin[1]	**277,354**	**262,572**	**14,782**	**5.6 %**				

** Direct transmission expense is exclusive of depreciation and depletion.*

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Appendix

Natural Gas Segment (Q3)

	Three Months Ended September 30,							
	Revenues		Change		Dekatherms (Dkt)		Average Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 11,667	$ 10,891	$ 776	7.1 %	937	890	218,071	215,448
South Dakota	2,140	2,036	104	5.1 %	104	109	43,210	42,719
Nebraska	2,216	2,344	(128)	(5.5) %	137	142	37,849	37,778
Residential	**16,023**	**15,271**	**752**	**4.9 %**	**1,178**	**1,141**	**299,130**	**295,945**
Montana	9,298	8,734	564	6.5 %	840	964	30,528	30,053
South Dakota	1,918	1,577	341	21.6 %	299	245	7,693	7,562
Nebraska	1,029	1,145	(116)	(10.1) %	131	134	5,138	5,071
Commercial	**12,245**	**11,456**	**789**	**6.9 %**	**1,270**	**1,343**	**43,359**	**42,686**
Industrial	767	680	87	12.8 %	1,140	928	248	243
Other	160	142	18	12.7 %	18	16	259	225
Total Retail Gas	**$ 29,195**	**$ 27,549**	**$ 1,646**	**6.0 %**	**3,606**	**3,428**	**342,996**	**339,099**
Regulatory amortization	7,496	5,240	2,256	43.1 %				
Transportation, wholesale, and other	13,445	14,412	(967)	(6.7) %				
Total Revenues	**$ 50,136**	**$ 47,201**	**$ 2,935**	**6.2 %**				
Total fuel, purchased supply, & direct transmission expense*	$ 11,010	$ 9,754	$ 1,256	12.9 %				
Utility Margin[1]	**$ 39,126**	**$ 37,447**	**$ 1,679**	**4.5 %**				

** Direct transmission expense is exclusive of depreciation and depletion.*

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

2026 Year-to-Date Appendix

Appendix

Year-to-Date 2026 Financial Results

($ in millions, except per share amounts)	Nine Months Ended September 30,			
	2026	2025	Variance	% Variance
Operating Revenues	$1,313.9	$1,196.3	$117.6	9.8%
Fuel, Purchased Supply, & Direct Transmission Expense (exclusive of depreciation and depletion)	342.7	300.4	42.3	14.1%
Utility Margin[1]	**971.3**	**895.9**	**75.4**	**8.4%**
Operating Expenses				
Operating and Maintenance	238.5	183.2	55.3	30.2%
Administrative and General	128.0	121.8	6.2	5.1%
Property and Other Taxes	151.0	137.5	13.5	9.8%
Depreciation and Depletion	200.9	187.6	13.3	7.1%
Total Operating Expenses	**718.4**	**630.1**	**88.3**	**14.0%**
Operating Income	**253.0**	**265.8**	**(12.8)**	**(4.8%)**
Interest Expense, net	(122.4)	(111.1)	11.3	10.2%
Other Income, net	10.6	9.1	1.5	16.5%
Income Before Income Taxes	**141.1**	**163.8**	**(22.7)**	**(13.9%)**
Income Tax Expense	(21.9)	(27.4)	(5.5)	(20.1%)
Net Income	**$119.2**	**$136.4**	**($17.2)**	**(12.6%)**
Effective Tax Rate	15.5%	16.7%	-1.2%	
Diluted Average Shares Outstanding	61.7	61.5	0.2	0.3%
Diluted Earnings per Share	$1.93	$2.22	($0.29)	(13.1%)
Dividends Paid per Common Share	$2.01	$1.98	$ 0.03	1.5%

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Note: Subtotal variances may exist due to rounding.

Appendix

Utility Margin (YTD)

($ in millions)

	Nine Months Ended September 30,			
	2026	2025	Variance	
Electric	$ 800.6	$ 725.2	$ 75.4	10.4%
Natural Gas	170.7	170.7	0.0	0.0%
Total Utility Margin[1]	**$ 971.3**	**$ 895.9**	**$ 75.4**	**8.4%**

Increase in utility margin due to the following factors:

$ 36.3	Base rates
15.5	Electric margin from the acquisition of the Puget Interests
6.7	Electric transmission revenue
5.2	Non-recoverable Montana electric supply costs
(4.1)	Montana property tax tracker collections
(3.4)	Electric retail volumes
(1.7)	Natural gas retail volumes (including a $5.2 million increase due to acquisition of Energy West Operations)
(1.2)	Natural gas production step down
2.8	Other
$ 56.1	**Change in Utility Margin Impacting Net Income**
$ 8.2	Operating expenses recovered in revenue, offset in operating & maintenance expense
7.6	Property and other taxes recovered in revenue, offset in property and other taxes
3.5	Production tax credits, offset in income tax expense
$ 19.3	**Change in Utility Margin Offset Within Net Income**
$ 75.4	**Increase in Consolidated Utility Margin**

Note: Subtotal variances may exist due to rounding.

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Appendix

Operating Expenses (YTD)

($ in millions)

	Nine Months Ended September 30,			
	2026	2025	Variance	
Operating & maintenance	$ 238.5	$ 183.2	$ 55.3	30.2%
Administrative & general	128.0	121.8	6.2	5.1%
Property & other taxes	151.0	137.5	13.5	9.8%
Depreciation & depletion	200.9	187.6	13.3	7.1%
Total Operating Expenses*	**$ 718.4**	**$ 630.1**	**$ 88.3**	**14.0%**

Increase in operating expenses due to the following factors:

$ 29.6	Electric generation maintenance (including $19.9 million and $11.9 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)
13.3	Depreciation expense due to plant additions and higher depreciation rates
8.0	Labor and benefits(1)
5.9	Property and other taxes not recoverable within trackers (including $4.7 million and $0.9 million due to the acquisition of the Colstrip Puget Interests and Avista Interests, respectively)
5.0	Wildfire mitigation expense, partly offset by higher base revenues
2.3	Merger-related costs, including consulting and legal fees
2.2	Technology implementation and maintenance expenses
0.9	Uncollectible accounts
0.6	Insurance expense
5.7	Other
$ 73.5	**Change in Operating Expense Items Impacting Net Income**
$ 8.2	Operating and maintenance expenses recovered in trackers, offset in revenue
7.6	Property and other taxes recovered in trackers, offset in revenue
(0.5)	Deferred compensation, offset in other income
(0.5)	Pension and other postretirement benefits, offset in other income(1)
$ 14.8	**Change in Operating Expense Items Offset Within Net Income**
$ 88.3	**Increase in Operating Expenses***

**Excluding fuel, purchased supply, and direct transmission expense.*

(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.

Appendix

Operating to Net Income (YTD)

($ in millions)

	Nine Months Ended September 30,			
	2026	2025	Variance	
Operating Income	**$ 253.0**	**$ 265.8**	**($12.8)**	**(4.8%)**
Interest Expense, net	(122.4)	(111.1)	11.3	10.2%
Other Income, net	10.6	9.1	1.5	16.5%
Income Before Income Taxes	**141.1**	**163.8**	**(22.7)**	**(13.9%)**
Income Tax Expense	(21.9)	(27.4)	(5.5)	(20.1%)
Net Income	**$ 119.2**	**$ 136.4**	**($17.2)**	**(12.6%)**

Note: Subtotal variances may exist due to rounding.

Appendix

Tax Reconciliation (YTD)

($ in millions)	Nine Months Ended September 30,				
	2026		2025		Variance
Income Before Income Taxes	**$ 141.1**		**$ 163.8**		**($22.7)**
Income tax calculated at federal statutory rate	29.6	21.0%	34.4	21.0%	(4.8)
State income tax, net of federal provision	1.9	1.3	1.0	0.6	0.9
Tax Credits					
Production tax credits	(2.0)	(1.4)	(4.0)	(2.4)	2.0
Other	-	-	0.7	0.4	(0.7)
Impact of utility ratemaking on income taxes					
Flow-through repairs deductions	(17.6)	(12.5)	(16.1)	(9.8)	(1.5)
Amortization of excess deferred income taxes	(2.7)	(1.9)	(1.2)	(0.7)	(1.5)
AFUDC, net	(1.1)	(0.8)	(1.1)	(0.7)	-
Plant and depreciation of flow-through items	12.9	9.1	10.0	6.1	2.9
Changes in Unrecognized Tax Benefits					
Interest and penalties	-	-	1.0	0.6	(1.0)
Nontaxable and nondeductible items					
Merger transaction costs	0.6	0.4	1.9	1.2	(1.3)
Other	0.2	0.1	0.5	0.3	(0.3)
Other	0.1	0.2	0.3	0.1	(0.2)
	(7.7)	(5.5)%	(7.0)	(4.3)%	(0.7)
Income Tax Expense and Effective Tax Rate	**$ 21.9**	**15.5%**	**$ 27.4**	**16.7%**	**$ (5.5)**

Appendix

Segment Results (YTD)

($ in thousands)

Nine Months Ended September 30, 2026	Electric	Gas	Total
Operating revenues	$ 1,059,932	$ 253,997	$ 1,313,929
Fuel, purchased supply, & direct transmission*	259,381	83,287	342,668
Utility margin [1]	800,551	170,710	971,261
Operating, general, and administrative	276,721	78,280	355,001
Property & other taxes	117,758	33,154	150,912
Depreciation & depletion	166,627	34,231	200,858
Operating income	239,445	25,045	264,490
Interest expense, net	(93,161)	(24,455)	(117,616)
Other income, net	6,772	2,725	9,497
Income tax (expense) benefit	(27,895)	60	(27,835)
Segment net income	$ 125,161	$ 3,375	$ 128,536
Reconciliation to consolidated net income			
Other, net [2]			(9,344)
Consolidated net income			$ 119,192

Nine Months Ended September 30, 2025	Electric	Gas	Total
Operating revenues	$ 954,702	$ 241,593	$ 1,196,295
Fuel, purchased supply, & direct transmission*	229,534	70,867	300,401
Utility margin [1]	725,168	170,726	895,894
Operating, general, and administrative	222,616	74,372	296,988
Property & other taxes	106,016	31,297	137,313
Depreciation & depletion	157,213	30,399	187,612
Operating income	239,323	34,658	273,981
Interest expense, net	(84,253)	(22,270)	(106,523)
Other income, net	5,886	2,838	8,724
Income tax expense	(25,465)	(2,102)	(27,567)
Segment net income	$ 135,491	$ 13,124	$ 148,615
Reconciliation to consolidated net income			
Other, net [2]			(12,214)
Consolidated net income			$ 136,401

**Direct transmission expense excludes depreciation and depletion.*

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

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

Appendix

Electric Segment (YTD)

	Nine Months Ended September 30,							
	Revenues		Change		Megawatt Hours (MWH)		Average Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
			(in thousands)					
Montana	$ 339,640	$ 307,589	$ 32,051	10.4 %	2,067	2,159	337,691	333,363
South Dakota	64,200	59,885	4,315	7.2 %	457	459	52,023	51,740
Residential	**403,840**	**367,474**	**36,366**	**9.9 %**	**2,524**	**2,618**	**389,714**	**385,103**
Montana	344,731	307,773	36,958	12.0 %	2,388	2,438	78,075	77,248
South Dakota	96,716	89,542	7,174	8.0 %	808	807	13,269	13,178
Commercial	**441,447**	**397,315**	**44,132**	**11.1 %**	**3,196**	**3,245**	**91,344**	**90,426**
Industrial	34,763	32,058	2,705	8.4 %	2,058	2,083	81	80
Other	35,120	28,507	6,613	23.2 %	137	133	28,640	28,671
Total Retail Electric	**915,170**	**825,354**	**89,816**	**10.9 %**	**7,915**	**8,079**	**509,779**	**504,280**
Regulatory amortization	(16,942)	38,995	(55,937)	(143.4) %				
Transmission	89,363	82,625	6,738	8.2 %				
Wholesale and other	72,341	7,728	64,613	836.1 %				
Total Revenues	**1,059,932**	**954,702**	**105,230**	**11.0 %**				
Total fuel, purchased supply, & direct transmission expense*	259,381	229,534	29,847	13.0 %				
Utility Margin[1]	**$ 800,551**	**$ 725,168**	**$ 75,383**	**10.4 %**				

** Direct transmission expense is exclusive of depreciation and depletion.*

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Appendix

Natural Gas Segment (YTD)

	Nine Months Ended September 30,							
	Revenues		Change		Dekatherms (Dkt)		Average Customer Counts	
	2026	2025	$	%	2026	2025	2026	2025
	(in thousands)							
Montana	$ 79,516	$ 80,277	$ (761)	(0.9) %	9,527	9,355	218,038	196,526
South Dakota	22,440	23,172	(732)	(3.2) %	2,271	2,420	43,273	42,867
Nebraska	17,573	20,076	(2,503)	(12.5) %	1,629	1,915	37,996	37,941
Residential	**119,529**	**123,525**	**(3,996)**	**(3.2) %**	**13,427**	**13,690**	**299,307**	**277,334**
Montana	48,386	45,991	2,395	5.2 %	6,208	5,777	30,554	27,743
South Dakota	17,813	16,672	1,141	6.8 %	2,521	2,448	7,725	7,551
Nebraska	9,529	10,932	(1,403)	(12.8) %	1,177	1,390	5,168	5,105
Commercial	**75,728**	**73,595**	**2,133**	**2.9 %**	**9,906**	**9,615**	**43,447**	**40,399**
Industrial	2,402	1,308	1,094	83.6 %	2,912	1,014	247	240
Other	952	1,003	(51)	(5.1) %	143	148	248	213
Total Retail Gas	**$ 198,611**	**$ 199,431**	**$ (820)**	**(0.4) %**	**26,388**	**24,467**	**343,249**	**318,186**
Regulatory amortization	12,420	993	11,427	1,150.8 %				
Transportation, wholesale, and other	42,966	41,169	1,797	4.4 %				
Total Revenues	**$ 253,997**	**$ 241,593**	**$ 12,404**	**5.1 %**				
Total fuel, purchased supply, & direct transmission expense*	$ 83,287	$ 70,867	$ 12,420	17.5 %				
Utility Margin[1]	**$ 170,710**	**$ 170,726**	**$ (16)**	**(0.0) %**				

** Direct transmission expense is exclusive of depreciation and depletion.*

(1) Utility Margin is a non-GAAP Measure. See appendix slide titled "Reconciling Gross Margin to Utility Margin" for additional disclosure.

Appendix

Year-to-Date 2026 Cash Flow

($ in millions)	Nine Months Ended September 30, 2026	2025
Operating Activities		
Net income	$ 119.2	$ 136.4
Adjustments to reconcile net income to cash provided by operations	224.3	213.6
Changes in working capital	22.5	(1.5)
Other noncurrent assets and liabilities	(1.9)	(10.2)
Cash Provided by Operating Activities	**364.1**	**338.3**
Cash Used in Investing Activities	**(466.7)**	**(418.5)**
Cash Provided by Financing Activities	**98.0**	**81.7**
Cash Provided by Operating Activities	**$ 364.1**	**$ 338.3**
Less: Changes in working capital	22.5	(1.5)
Funds from Operations	**$ 341.6**	**$ 339.8**
Property, plant, and equipment additions	464.0	374.5
Capital expenditures included in trade accounts payable	(18.3)	4.3
AFUDC Credit	7.8	7.0
Total Capital Investment	**$ 453.5**	**$ 385.8**

Cash from Operating Activities increased by $25.8 million. The increase in cash provided by working capital is primarily due to an increase in our net cash inflows for energy supply costs, as shown in the table below.

Funds from Operations increased by $1.8 million over prior period.

Net Under-Collected Supply Costs
($ in millions)

	Beginning (Jan. 1)	Ending (Sept. 30)	(Outflow) / Inflow
2025	$5.9	$26.6	**($20.7)**
2026	$44.8	$34.8	**$10.0**
	2026 Increase in Net Cash Inflows		**$30.7**

No Planned Equity Issuances in 2026

Financing plans (targeting a FFO to Debt ratio > 14%) are expected to maintain our current credit ratings and are subject to change

Debt financing in 2026

- Amended our existing NorthWestern Energy Group $150 million term loan to extend the maturity date from April 10, 2026 to December 31, 2026 in Q2.
- Issued $150 million, 5.51% coupon, 10-year South Dakota FMBs in Q2.
- Entered $225 million NorthWestern Corp. Term Loan Credit Agreement with a maturity date of November 26, 2027 in Q2.
- Increased our NW Corp revolver capacity from $425 million to $500 million and our NorthWestern Energy Group and NWE Public Service revolver capacity from $200 million to $250 million in Q3 (no impact to maturity date or borrowing rates).

Appendix

Balance Sheet

($ in millions)	As of September 30, 2026	As of December 31, 2025
Cash and cash equivalents	$ 6.5	$ 8.8
Restricted cash	19.5	22.0
Accounts receivable, net	183.0	209.8
Inventories	153.2	132.5
Other current assets	161.4	130.9
Goodwill	367.6	367.6
PP&E and other noncurrent assets	7,935.6	7,588.1
Total Assets	**$ 8,827.0**	**$ 8,459.7**
Payables	112.4	129.6
Current maturities - debt and finance leases	101.7	256.8
Other current liabilities	365.9	311.0
Long-term debt & finance leases	3,566.8	3,181.0
Other noncurrent liabilities	1,792.9	1,695.5
Shareholders' equity	2,887.2	2,885.7
Total Liabilities and Equity	**$ 8,827.0**	**$ 8,459.7**
Capitalization:		
Short-Term Debt & Short-Term Finance Leases	101.7	256.8
Long-Term Debt & Long-Term Finance Leases	3,566.8	3,181.0
Less: Short- and Long-Term Finance Leases	(9.0)	(1.9)
Shareholders' Equity	2,887.2	2,885.7
Total Capitalization	**$ 6,546.7**	**$ 6,321.7**
Ratio of Debt to Total Capitalization	**55.9%**	**54.4%**

Debt to Total Capitalization slightly up from last quarter and just above our targeted 50% - 55% range.

Appendix

Reconciling Gross Margin to Utility Margin

Reconciliation of Gross Margin to Utility Margin for the Three Months Ended September 30,

	Electric		Natural Gas		Total	
	2026	2025	2026	2025	2026	2025
($ in millions)						
Reconciliation of gross margin to utility margin:						
Operating Revenues	$ 373.7	$ 339.8	$ 50.1	$ 47.2	$ 423.8	$ 387.0
Less: Fuel, purchased supply, and direct transmission expense (exclusive of depreciation and depletion shown separately below)	96.3	77.2	11.0	9.8	107.3	87.0
Less: Operating and maintenance	69.4	48.6	15.5	15.5	84.9	64.1
Less: Property and other taxes	39.5	35.4	11.0	10.7	50.5	46.1
Less: Depreciation and depletion	55.6	52.3	11.4	10.5	67.0	62.8
Gross Margin	**112.9**	**126.3**	**1.2**	**0.7**	**114.1**	**127.0**
Add back: Operating and maintenance	69.4	48.6	15.5	15.5	84.9	64.1
Add back: Property and other taxes	39.5	35.4	11.0	10.7	50.5	46.1
Add back: Depreciation and depletion	55.6	52.3	11.4	10.5	67.0	62.8
Utility Margin (1)	**$ 277.4**	**$ 262.6**	**$ 39.1**	**$ 37.4**	**$ 316.5**	**$ 300.0**

Reconciliation of Gross Margin to Utility Margin for the Nine Months Ended September 30,

	Electric		Natural Gas		Total	
	2026	2025	2026	2025	2026	2025
($ in millions)						
Reconciliation of gross margin to utility margin:						
Operating Revenues	$1,060.0	$ 954.7	$ 254.0	$ 241.6	$1,314.0	$1,196.3
Less: Fuel, purchased supply, and direct transmission expense (exclusive of depreciation and depletion shown separately below)	259.4	229.5	83.3	70.9	342.7	300.4
Less: Operating and maintenance	192.3	139.8	46.2	43.4	238.5	183.2
Less: Property and other taxes	117.8	106.0	33.2	31.3	151.0	137.3
Less: Depreciation and depletion	166.7	157.2	34.2	30.4	200.9	187.6
Gross Margin	**323.8**	**322.2**	**57.1**	**65.6**	**380.9**	**387.8**
Plus: Operating and maintenance	192.3	139.8	46.2	43.4	238.5	183.2
Plus: Property and other taxes	117.8	106.0	33.2	31.3	151.0	137.3
Plus: Depreciation and depletion	166.7	157.2	34.2	30.4	200.9	187.6
Utility Margin (1)	**$ 800.6**	**$ 725.2**	**$ 170.7**	**$ 170.7**	**$ 971.3**	**$ 895.9**

Management believes 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, 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 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.

Note: Subtotal variances may exist due to rounding.

(1) Utility Margin is a non-GAAP Measure.

Appendix

PCCAM Impact by Quarter

Pre-Tax $ Millions – Shareholder (Detriment) Benefit

	Q1	Q2	Q3	Q4	Full Year
'17/'18 Tracker	First full year recorded in Q3		$3.3		$3.3
'18/'19 Tracker			($5.1)	$0.3	(4.8)
2018 (Expense) Benefit	**$0.0**	**$0.0**	**($1.8)**	**$0.3**	**($1.5)**

	Q1	Q2	Q3	Q4	Full Year
'18/'19 Tracker	($1.6)	$4.6			$3.0
'19/'20 Tracker			$0.1	($0.7)	(0.6)
2019 (Expense) Benefit	**($1.6)**	**$4.6**	**$0.1**	**($0.7)**	**$2.4**

	Q1	Q2	Q3	Q4	Full Year
CU4 Disallowance ('18/'19 Tracker)				($9.4)	($9.4)
'19/'20 Tracker	($0.1)	**$0.2**			$0.1
Recovery of modeling costs	$0.7				$0.7
'20/'21 Tracker			($0.6)	($0.3)	($0.9)
2020 (Expense) Benefit	**$0.6**	**$0.2**	**($0.6)**	**($0.3)**	**($0.1)**

	Q1	Q2	Q3	Q4	Full Year
'20/'21 Tracker	($0.8)	($0.5)			($1.3)
'21/'22 Tracker			($2.7)	($1.4)	($4.1)
2021 (Expense) Benefit	**($0.8)**	**($0.5)**	**($2.7)**	**($1.4)**	**($5.4)**

	Q1	Q2	Q3	Q4	Full Year
'21/'22 Tracker	($0.8)	($0.8)			($1.6)
'22/'23 Tracker			($3.9)	($1.7)	($5.6)
2022 (Expense) Benefit	**($0.8)**	**($0.8)**	**($3.9)**	**($1.7)**	***($7.2)***

	Q1	Q2	Q3	Q4	Full Year
'22/'23 Tracker	$0.5	$2.1			$2.6
Retro-active application of PCCAM base				$3.2	$3.2
'23/'24 Tracker			$0.1	$1.1	$1.2
2023 (Expense) Benefit	**$0.5**	**$2.1**	**$0.1**	**$4.3**	**$7.0**

	Q1	Q2	Q3	Q4	Full Year
'23/'24 Tracker	($3.0)	$1.2			($1.8)
'24/'25 Tracker			$0.7	$0.2	$0.9
2024 (Expense) Benefit	**($3.0)**	**$1.2**	**$0.7**	**$0.2**	**($0.9)**

	Q1	Q2	Q3	Q4	Full Year
'24/'25 Tracker	($2.7)	($0.8)			($3.5)
'25/'26 Tracker			($2.3)	($2.3)	($4.6)
2025 (Expense) Benefit	**($2.7)**	**($0.8)**	**($2.3)**	**($2.3)**	**($8.2)**

	Q1	Q2	Q3	Q4	Full Year
'25/'26 Tracker	($0.7)	$0.0			($0.7)
'26/'27 Tracker			$0.0		$0.0
2026 (Expense) Benefit	**($0.7)**	**$0.0**	**$0.0**	**$0.0**	**($0.7)**
Year-over-Year Variance 2025 - 2026	***$2.0***	***$0.8***	***$2.3***		***$5.1***

Note:
- *Effective February 1, 2026 the cost sharing mechanism of the PCCAM was suspended on an interim basis pending further review by the MPSC.*
- *Subtotal variances may exist due to rounding.*

Appendix

Qualified Facility Earnings Adjustment

(Millions)	Annual actual contract price escalation	Annual adjustment for actual output and pricing	Adjustment associated with the one-time clarification in contract term	Total
Nov-12	(Arbitration) $47.9 Non-GAAP Adj.	$0.0	$0.0	$47.9
Jun-13	$0.0	1.0	0.0	**$1.0**
Jun-14	$0.0	0.0	0.0	**$0.0**
Jun-15	($6.1) Non-GAAP Adj.	1.8	0.0	**($4.3)**
Jun-16	$0.0	1.8	0.0	**$1.8**
Jun-17	$0.0	2.1	0.0	**$2.1**
Jun-18	$17.5 Non-GAAP Adj.	9.7	0.0	**$27.2**
Jun-19	$3.3	3.1	0.0	**$6.4**
Jun-20	$2.2	0.9	0.0	**$3.1**
Jun-21	($2.1)	2.6	8.7 Non-GAAP Adj.	**$9.2**
Sep-21	$0.0	0.0	(1.3) Non-GAAP Adj.	($1.3)
Dec-21	$0.0	0.0	(0.4) Non-GAAP Adj.	($0.4)
Jun-22	$3.3	1.8	0.0	**$5.1**
Jun-23	$4.2	0.8	0.0	**$5.0**
Jun-24	$0.0	0.8	0.0	**$0.8**
Jun-25	$0.0	0.8	0.0	**$0.8**
Jun-26	$0.0	0.9	0.0	**$0.9**
Year-over-Year Better (Worse)				
2013	($47.9)	1.0	0.0	**($46.9)**
2014	$0.0	(1.0)	0.0	**($1.0)**
2015	($6.1)	1.8	0.0	**($4.3)**
2016	$6.1	0.0	0.0	**$6.1**
2017	$0.0	0.3	0.0	**$0.3**
2018	$17.5	7.6	0.0	**$25.1**
2019	($14.2)	(6.6)	0.0	**($20.8)**
2020	($1.1)	(2.2)	0.0	**($3.3)**
2021	($4.3)	$1.7	$7.0	**$4.4**
2022	$5.4	($0.8)	($7.0)	**($2.4)**
2023	$0.9	($1.0)	$0.0	**($0.1)**
2024	($4.2)	$0.0	$0.0	**($4.2)**
2025	$0.0	$0.0	$0.0	**$0.0**
2026	$0.0	$0.1	$0.0	**$0.1**

Our electric QF liability consists of unrecoverable costs associated with contracts covered under PURPA that are part of a 2002 stipulation with the MPSC and other parties. Risks / losses associated with these contracts are born by shareholders, not customers. Therefore, any mitigation of prior losses and / or benefits of liability reduction also accrue to shareholders.

Appendix

Non-GAAP Financial Measures

Pre-Tax Adjustments ($ Millions)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reported GAAP Pre-Tax Income	$ 156.5	$ 176.1	$ 178.3	$ 182.2	$ 144.2	$ 190.2	$ 182.4	$ 201.6	$ 214.7	$ 187.6
Non-GAAP Adjustments to Pre-Tax Income:										
Weather	15.2	(3.4)	(1.3)	(7.3)	9.8	1.1	(8.9)	4.3	10.6	14.4
Lost revenue recovery related to prior periods	(14.2)	-	-	-	-	-	-	-	-	-
QF liability adjustment	-	-	(17.5)	-	-	(6.9)	-	-	-	-
Electric tracker disallowance of prior period costs	12.2	-	-	-	9.9	-	-	-	-	-
Income tax adjustment	-	-	9.4	-	-	-	-	-	-	-
Community Renewable Energy Project Penalty	-	-	-	-	-	-	2.5	-	(2.3)	1.3
Impairment of Alternative Energy Storage Investment	-	-	-	-	-	-	-	-	4.2	-
NWE-BKH Merger Transaction Costs (not tax deductible)	-	-	-	-	-	-	-	-	-	9.3
Regulatory Disallowance of Certain YCGS Capital Costs	-	-	-	-	-	-	-	-	-	31.2
Remove Q4 2025 PCCAM Expense Following Suspension of 90/10 Sharing	-	-	-	-	-	-	-	-	-	2.3
Adjusted Non-GAAP Pre-Tax Income	$ 169.7	$ 172.7	$ 168.9	$ 174.9	$ 163.9	$ 184.4	$ 176.0	$ 205.9	$ 227.2	$ 246.1

Tax Adjustments to Non-GAAP Items ($ Millions)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GAAP Net Income	$ 164.2	$ 162.7	$ 197.0	$ 202.1	$ 155.2	$ 186.8	$ 183.0	$ 194.1	$ 224.1	$ 181.1
Non-GAAP Adjustments Taxed at 38.5% ('12-'17) and 25.3% ('18-current):										
Weather	9.3	(2.1)	(1.0)	(5.5)	7.3	0.8	(6.6)	3.2	7.9	10.8
Lost revenue recovery related to prior periods	(8.7)	-	-	-	-	-	-	-	-	-
QF liability adjustment	-	-	(13.1)	-	-	(5.2)	-	-	-	-
Electric tracker disallowance of prior period costs	7.5	-	-	-	7.4	-	-	-	-	-
Income tax adjustment	(12.5)	-	(12.8)	(22.8)	-	-	-	-	-	-
Community Renewable Energy Project Penalty	-	-	-	-	-	-	2.5	-	(2.3)	1.3
Previously claimed AMT credit	-	-	-	-	-	-	-	3.2	-	-
Release of Unrecognized Tax Benefit	-	-	-	-	-	-	-	(3.2)	(16.9)	(7.4)
Impairment of Alternative Energy Storage Investment	-	-	-	-	-	-	-	-	3.1	-
Natural Gas Safe Harbor Method Change	-	-	-	-	-	-	-	-	(7.0)	-
NWE-BKH Merger Transaction Costs (not tax deductible)	-	-	-	-	-	-	-	-	-	9.3
Regulatory Disallowance of Certain YCGS Capital Costs	-	-	-	-	-	-	-	-	-	23.3
Remove Q4 2025 PCCAM Expense Following Suspension of 90/10 Sharing	-	-	-	-	-	-	-	-	-	1.7
Non-GAAP Net Income	$ 159.8	$ 160.6	$ 170.1	$ 173.8	$ 169.9	$ 182.4	$ 178.9	$ 197.3	$ 208.9	$ 220.1

Non-GAAP Diluted Earnings per Share	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Diluted Average Shares (Millions)	*48.5*	*48.7*	*50.2*	*50.8*	*50.7*	*51.9*	*56.3*	*60.4*	*61.4*	*61.5*
Reported GAAP Diluted Earnings per Share	$ 3.39	$ 3.34	$ 3.92	$ 3.98	$ 3.06	$ 3.60	$ 3.25	$ 3.22	$ 3.65	$ 2.94
Non-GAAP Adjustments:										
Weather	0.19	(0.04)	(0.02)	(0.11)	0.14	0.01	(0.11)	0.05	0.13	0.18
Lost revenue recovery related to prior periods	(0.18)	-	-	-	-	-	-	-	-	-
QF liability adjustment	-	-	(0.26)	-	-	(0.10)	-	-	-	-
Electric tracker disallowance of prior period costs	0.16	-	-	-	0.15	-	-	-	-	-
Income tax adjustment	(0.26)	-	(0.25)	(0.45)	-	-	-	-	-	-
Community Renewable Energy Project Penalty	-	-	-	-	-	-	0.04	-	(0.04)	0.02
Previously claimed AMT credit	-	-	-	-	-	-	-	0.05	-	-
Release of Unrecognized Tax Benefit	-	-	-	-	-	-	-	(0.05)	(0.28)	(0.12)
Impairment of Alternative Energy Storage Investment	-	-	-	-	-	-	-	-	0.05	-
Natural Gas Safe Harbor Method Change	-	-	-	-	-	-	-	-	(0.11)	-
NWE-BKH Merger Transaction Costs (not tax deductible)	-	-	-	-	-	-	-	-	-	0.15
Regulatory Disallowance of Certain YCGS Capital Costs	-	-	-	-	-	-	-	-	-	0.38
Remove Q4 2025 PCCAM Expense Following Suspension of 90/10 Sharing	-	-	-	-	-	-	-	-	-	0.03
Non-GAAP Diluted Earnings per Share	$ 3.30	$ 3.30	$ 3.39	$ 3.42	$ 3.35	$ 3.51	$ 3.18	$ 3.27	$ 3.40	$ 3.58

Appendix

Non-GAAP Financial Measures

This presentation includes financial information prepared in accordance with GAAP, as well as other financial measures, such as Utility Margin, Adjusted Non-GAAP pretax income, Adjusted Non-GAAP net income and Adjusted Non-GAAP Diluted EPS that are considered “non-GAAP financial measures.” 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 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 Consolidated Statements of Income. A reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure, is included in this presentation.

Management believes 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, 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 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.

Management also believes the presentation of Adjusted Non-GAAP pre-tax income, Adjusted Non-GAAP net income and Adjusted Non-GAAP Diluted EPS is more representative of normal earnings than GAAP pre-tax income, net income and EPS due to the exclusion (or inclusion) of certain impacts that are not reflective of ongoing earnings. The presentation of these non-GAAP measures is intended to supplement investors' understanding of our financial performance and not to replace other GAAP measures as an indicator of actual operating performance. Our measures may not be comparable to other companies' similarly titled measures.

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