



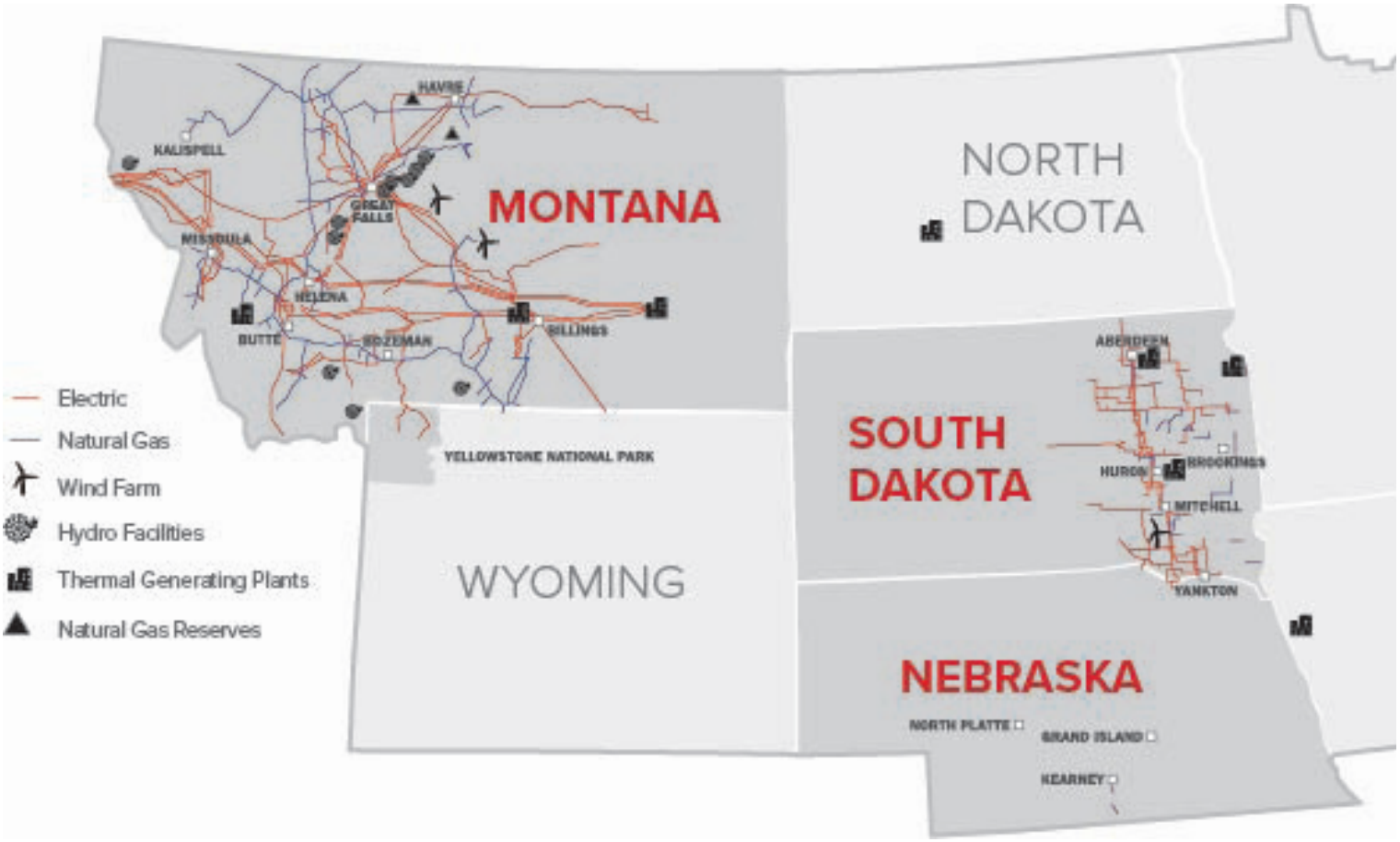
2025 ANNUAL REPORT



NorthWestern® Energy

Delivering a Bright Future

Service Territory



NorthWestern Energy provides electricity and natural gas in the upper Midwest and Northwest, serving approximately 850,300 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. Our business consists of federal- and state-regulated operations, including electric and natural gas distribution and transmission, electric generation and natural gas production.

YEAR-END SHARE PRICE

2021	$57.16
2022	$59.34
2023	$50.89
2024	$53.46
2025	$64.54

BASIC EARNINGS PER SHARE

2021	$3.61
2022	$3.25
2023	$3.22
2024	$3.66
2025	$2.95

DIVIDENDS PER SHARE

2021	$2.48
2022	$2.52
2023	$2.56
2024	$2.60
2025	$2.64

NET PROPERTY, PLANT & EQUIPMENT (IN BILLIONS)

2021	$5.25
2022	$5.66
2023	$6.04
2024	$6.40
2025	$6.74

MT ELECTRIC

440,700 customers in 225 communities

6,596 miles of transmission lines

18,946 miles of distribution lines

1,660 MW nameplate owned power generation

SD ELECTRIC

65,600 customers in 118 communities

1,344 miles of transmission lines

2,386 miles of distribution lines

420 MW nameplate owned power generation

MT NATURAL GAS

249,400 customers in 123 communities

5,939 miles of distribution pipelines

2,133 miles of intrastate transmission pipelines

18 Bcf gas storage

25 Bcf owned proven natural gas reserves

SD NATURAL GAS

51,200 customers in 82 communities

1,853 miles of distribution pipeline

55 miles of intrastate transmission pipelines

NE NATURAL GAS

43,400 customers in 4 communities

836 miles of pipelines



A LETTER FROM OUR **CEO:**

As we reflect on 2025, NorthWestern Energy stands at a pivotal moment — one defined by strategic growth, continuous improvement and our commitment to powering progress today and tomorrow. This year, our commitment to delivering safe, reliable and affordable energy has been matched by transformative actions and strong stock performance, all while preparing for an exciting new chapter as we work to position ourselves well for a changing utility environment.

2025 was a year of change for the utility environment, and we don't expect those changes to slow down in the coming years. This rapid transformation is driven by evolving customer expectations, technological innovation and shifting regulatory landscapes. Today's energy companies must navigate increasing demand for reliable, affordable and sustainable energy while adapting to new challenges such as severe weather events, cybersecurity risks, and serving new large-load customers. At the same time, industry consolidation and strategic partnerships are reshaping the competitive landscape and enabling energy companies to achieve greater scale, resilience and efficiency. Our dedicated team of 1,667 employees continues to rise to these challenges and find innovative solutions. As we look ahead, these changes require us to remain agile, invest in modern infrastructure and embrace innovation to continue powering progress for our customers and communities — today and tomorrow.



STRATEGIC MERGER: BUILDING A PREMIER REGIONAL UTILITY

In August, NorthWestern Energy and Black Hills Corporation (Black Hills) announced a definitive agreement to combine in an all-stock, tax-free merger. Our merger with Black Hills is a bold step in powering progress for our customers and communities — today, by enhancing reliability and scale, and tomorrow, by positioning us for sustainable growth.

This transaction will create a premier regional regulated electric and natural gas company, serving approximately 2.1 million customers across eight contiguous states. The combined company will have a market capitalization of $9.8 billion and an enterprise value of $18 billion as of Feb. 23, 2026. This merger is expected to be accretive to both companies' earnings per share (EPS) in the first year and supports an increased long-term EPS target growth rate of 5% to 7%, up from 4% to 6%. The merger is expected to close in the second half of 2026.

Key benefits for investors include:

- Increased scale across contiguous service territory enhances diversification, resulting in a more resilient company to safely, reliably, and cost-effectively meet customers' growing energy needs.
- Strong and predictable earnings and cash flows with more efficient access to capital to be credit enhancing and support a high-quality credit profile.
- Better positioned to capture accretive growth opportunities together than either company could achieve independently.
- Combines two complementary teams with shared cultures focused on operational excellence and exceptional customer service.



ENERGY WEST **ACQUISITION**

A major milestone in 2025 was the successful acquisition of Energy West's natural gas distribution system in Montana. This transaction added approximately 33,000 natural gas customers and 43 skilled employees to our Montana operations, expanding our footprint in Great Falls and surrounding communities.

The acquisition strengthens our ability to deliver safe and reliable service by integrating Energy West's infrastructure into our existing network. It also provides operational synergies and positions us to better manage supply and demand across a broader service area today and into the future.



REGULATORY AND LEGISLATIVE

In 2025, NorthWestern Energy continued to advance its operational and regulatory priorities, strengthening our foundation for long-term growth and resilience. Through proactive engagement with regulators and strategic investments, we secured constructive rate settlements across key jurisdictions, enhanced our risk management framework with forward-thinking wildfire legislation and expanded our customer base through a strategic acquisition. These achievements underscore our commitment to delivering reliable service, managing risk and positioning the company for sustainable value creation in a dynamic energy landscape.

Constructive rate review settlements in Montana and Nebraska marked a significant achievement for NorthWestern Energy in 2025. These regulatory outcomes were the result of proactive engagement with state commissions and stakeholders, reflecting our commitment to transparency and collaboration. The settlements enable us to recover increased system investments, operating costs driven by inflation and evolving service requirements, while ensuring we can continue to provide safe, reliable and affordable energy to our customers. By securing fair and timely cost recovery, we strengthen our ability to invest in critical infrastructure and maintain high standards of



PROGRESS

service across our territories well into the future. As we navigate a dynamic energy landscape, these constructive rate outcomes provide a solid foundation for sustainable growth and long-term value creation for all stakeholders.

The passage of Montana House Bill 490 in 2025 represents a major advancement in NorthWestern Energy's approach to wildfire risk management. This forward-thinking legislation, which received broad bipartisan support, establishes clear liability protections for electric utilities operating in the state. House Bill 490 supports our ongoing commitment to safety and reliability by encouraging continued investment in wildfire prevention and grid hardening. The legislation reduces the risk of unpredictable legal exposure and incentivizes utilities to proactively manage wildfire threats through robust mitigation plans. By clarifying the legal standards and limiting strict liability for wildfire-related damages, the bill provides much-needed regulatory certainty for our operations. This clarity enables NorthWestern Energy to plan and execute wildfire mitigation strategies with greater confidence, knowing that prudent investments and actions — when aligned with an approved mitigation plan — are recognized and protected under state law.



GROWTH AND INFRASTRUCTURE

On the first day of 2026, NorthWestern Energy became the majority owner of Colstrip Units 3 and 4, increasing our ownership stake to 55%. Our acquisition of Puget Sound Energy's 370-megawatt share and Avista's 222-megawatt share of the Colstrip Plant at zero cost will allow us to provide energy in a more affordable manner than if we had built a new generation resource. This strategic acquisition is a cornerstone of our commitment to providing reliable and cost-effective energy for Montana customers, today and tomorrow. The 222-megawatt Avista share will allow us to meet resource adequacy for our Montana customers and the 370-megawatt Puget Sound share provides us with excess capacity to serve data centers and other large-load customers. With majority ownership, NorthWestern gains greater operational control and the ability to guide future investments and maintenance decisions at the facility. This ensures the plant continues to deliver cost-effective on-demand, 24/7 generating capacity..

In South Dakota, an existing diesel-fired 28.8-megawatt generating plant in the Aberdeen area is being replaced with two new natural gas turbines, expected to begin serving our South Dakota customers in 2026. This upgrade improves efficiency and will increase the system's reliability, ensuring we can meet customers' energy needs in all weather conditions. We are also advancing regional reliability through the planned construction of a new 131-megawatt natural gas generation facility in Aberdeen,



INVESTMENTS

South Dakota. This project is a direct response to updated resource accreditation and planning reserve margin requirements from the Southwest Power Pool, reflecting the region's growing demand for dependable energy. The new facility will provide flexible, dispatchable generation to help balance the variability of renewable resources and meet peak demand, ensuring our customers continue to receive uninterrupted service. With an anticipated investment of approximately $300 million, this expansion is not only a testament to our commitment to reliability but also a key component of our long-term capital investment strategy.

With over $3.2 billion in grid modernization investments planned for 2026 through 2030, we are powering progress by strengthening our infrastructure for today's needs and tomorrow's opportunities. These investments focus on upgrading transmission, generation and distribution infrastructure across our service territories. By enhancing and hardening our grid, we are preparing for the increasing threats posed by severe weather, wildfires and cybersecurity risks. Our modernization efforts also support the integration of renewable energy resources, improve service reliability, and enable us to meet the evolving needs of our customers and communities. These forward-looking investments are foundational to our strategy for sustainable growth and long-term value creation for all stakeholders today and in the future.



CUSTOMER AND COMMUNITY

Delivering uninterrupted power is at the heart of NorthWestern Energy's mission. In 2025, our customers experienced exceptional electric reliability, with uninterrupted service 99.985% of the time. We consistently deliver electric reliability that places our performance in the first or second quartile amongst our peer utilities. This is meaningful when you consider our large rural and rugged service territories. This achievement reflects our ongoing investments in grid modernization and proactive maintenance.

This high level of reliability is especially important as our service territory faces increasingly complex challenges, including severe weather events and growing energy demand from new industries such as data centers. For more than a decade, grid resiliency has been a major focus for NorthWestern Energy. Despite the challenges posed by our rural service territory, our reliability consistently outperforms that of our industry peers. Our reliable service is due in large part to our Distribution System Infrastructure Project (DSIP), which began in 2011 with the goal of heading off potential problems with aging infrastructure, addressing capacity needs and laying the foundation for increasing technology deployment, and still continues today.

In addition to grid resiliency, we invest in many customer-facing programs, which has helped us outperform many of our peers in customer satisfaction scores. Our investment in Advanced Metering Infrastructure allowed us to change the way we communicate with our customers. In mid-2025, we launched our Preference Center,



FOCUS

which allows customers to sign up for alerts regarding their billing, payments, outages, safety, company news and more. Our commitment to reliability and advanced technology supports our customers' daily lives and business operations and reinforces our reputation as a trusted energy partner in the communities we serve.

NorthWestern Energy's dedication to community engagement goes far beyond providing energy. In 2025, the company contributed $2.1 million in charitable giving to 414 communities across our three-state service territory. These contributions supported a wide range of local initiatives, from disaster relief and educational programs to scholarships and economic development. We also provided $1.54 million to fish and wildlife projects and $630,000 in recreation funds.

Our employees are active volunteers, lending their time and expertise to causes that strengthen the social fabric of the places they call home.

Our commitment to charitable giving and volunteerism is about powering progress in the communities we serve — supporting well-being and growth now and fostering resilience for the future. We believe supporting community organizations and local development is essential to building resilient, vibrant communities. By investing in the well-being of our neighbors, NorthWestern Energy helps ensure the benefits of reliable energy extend beyond the grid, fostering growth, opportunity and a higher quality of life for all.



SUSTAINABILITY

At NorthWestern Energy, our commitment to sustainability is at the heart of how we power progress today and tomorrow. Sustainability goes far beyond environmental issues. It also encapsulates safety, employee engagement and financial strength. Sustainability means meeting the needs of our customers and communities today, while planning and investing for a brighter tomorrow. This enduring focus is built on financial soundness, constructive policy and a culture of integrity. Our dedication to sustainability is the reason we've been in business for more than 100 years, and the reason we will continue to thrive. Sustainability guides our actions as we serve some of the most beautiful regions in the country.

We recognize that every decision we make impacts the environment, and through our environmental programs, we actively seek ways to protect and enhance rivers, streams and habitats. As the owner and operator of 11 hydroelectric facilities in Montana, habitat improvement is a top priority for our Protection,



PLANNING FOR THE FUTURE

Mitigation, and Enhancement program. Our avian protection initiatives, including building nesting platforms for ospreys and ensuring new power poles are avian safe, further demonstrate our commitment to safeguarding wildlife.

Powering progress also means investing in our workforce. We offer competitive pay and comprehensive benefits to our employees, who are our most valuable asset. As an Equal Opportunity Employer, we provide attractive salaries, robust retirement contributions, and a wide range of health and wellness plans, all designed to meet the diverse needs of our team. Our number one goal is employee health and safety, and our strong safety culture ensures we watch out for one another every day.

By integrating sustainability into every aspect of our operations, we are powering progress today and ensuring tomorrow's success — for our employees, our customers, our communities and our shareholders.

FINANCIAL PERFORMANCE AND OPERATIONAL **EFFICIENCY**

Our disciplined cost management and operational efficiency are not just driving results today — they are laying the groundwork for future progress, ensuring NorthWestern Energy remains a resilient and forward-looking utility.

We invested nearly $590 million in 2025 into our utility operations to support reliability and growth projects. We strive to deliver long-term financial value to our shareholders. This past year we paid a dividend of $2.64 per share, which was a dividend yield of 4.1% on our stock price at year end. Our stock price performed well this year, achieving a 26.4% total shareholder return driven by the expected merger with Black Hills, our growth initiatives, and constructive rate reviews in our jurisdictions. Importantly, we continue to deliver value through disciplined cost management and operational efficiency.

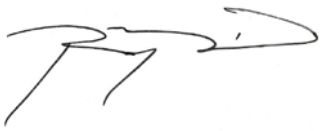
LOOKING **AHEAD**

As we prepare to join forces with Black Hills, our focus remains on delivering shareholder value, supporting our communities and powering progress for all stakeholders. We are proud of our dedicated workforce of highly engaged employees, and we look forward to combining our talented team with the great team at Black Hills. The combined company will be well-positioned to meet rising energy demand, accelerate investment in critical infrastructure, and advance a clean energy future.

As we prepare for many exciting changes ahead, we're also focused on what will not change: our SERVICE values of safety, excellence, respect, value, integrity, community and environment. These values are as important now as they were a decade ago when we drafted them. Our SERVICE values continue to keep us working together and fulfilling our commitment to one another and to the communities we serve, while helping keep each other and our customers safe.

Thank you for your continued trust and support as we power progress today and tomorrow — building a brighter, more resilient future together.

Sincerely,



Brian Bird
President & CEO, NorthWestern Energy

Executive Team



Brian Bird

President and Chief Executive Officer

In current position since 2023. Previously Chief Financial Officer from 2003-2021 and President and Chief Operating Officer from 2021-2022. Experience with energy and other large industrial companies since 1986.



Crystal Lail

Chief Financial Officer

Responsible for accounting, financial reporting, payroll, accounts payable, regulatory accounting, SOX controls, treasury, internal audit, enterprise risk management, financial planning and analysis, tax, investor relations, compensation and benefits. Current position since 2021. In energy industry since 2003.



Shannon Heim

General Counsel and Vice President - Federal Government Affairs

Responsible for all in-house and outside legal activities, federal government affairs, FERC compliance, risk management and contracts. Current position since 2023.



Michael Cashell

Vice President - Transmission

Responsible for all electric transmission and natural gas transmission, storage operations, NERC compliance, physical security and support services. Current position since 2011. In energy industry since 1986.



John Hines

Vice President - Supply and Montana Government Affairs

Responsible for electric and natural gas planning, procurement and generation operations, the company's environmental function and Montana's government affairs. Current position since 2011. In energy industry since 1989.



Bleau LaFave

Vice President - Asset Management and Business Development

Responsible for distribution and transmission asset management, long-term resources and business development. Current position since 2023. In energy industry since 1994.



Jason Merkel

Vice President - Distribution

Responsible for electric and natural gas distribution operations, and substation operations. Current position since 2022. In energy industry since 1993.



Bobbi Schroeppel

Vice President - Customer Care, Communications and Human Resources

Responsible for customer care, economic development, key account management, community relations, corporate communications, human resources, labor relations and safety. Current position since 2002. In energy industry since 1994.



Jeanne Vold

Vice President - Technology

Responsible for technology operations and deployment, cyber security, network operations and strategic direction. Current position since 2021. In energy industry since 1999.

Board of Directors



Brian Bird
Director, President and Chief Executive Officer

Director since January 2023



Sherina Maye Edwards
Director

Committees: Nominating and Governance; Human Resources

Director since April 2023



Dave Goodin
Director

Committees: Audit, Operations

Director since December 2024



Jan Horsfall
Director, Operations Committee Chair

Committees: Operations (Chair), Audit

Director since April 2015



Britt Ide
Director, Nominating and Governance Committee Chair

Committees: Nominating and Governance; Human Resources

Director since April 2017



Kent Larson
Director

Committees: Audit, Operations

Director since July 2022



Linda Sullivan
Board Chair

Director since April 2017



Mahvash Yazdi
Director, Human Resources Committee Chair

Committees: Human Resources (Chair), Operations

Director since December 2019



Jeffrey Yingling
Director, Audit Committee Chair

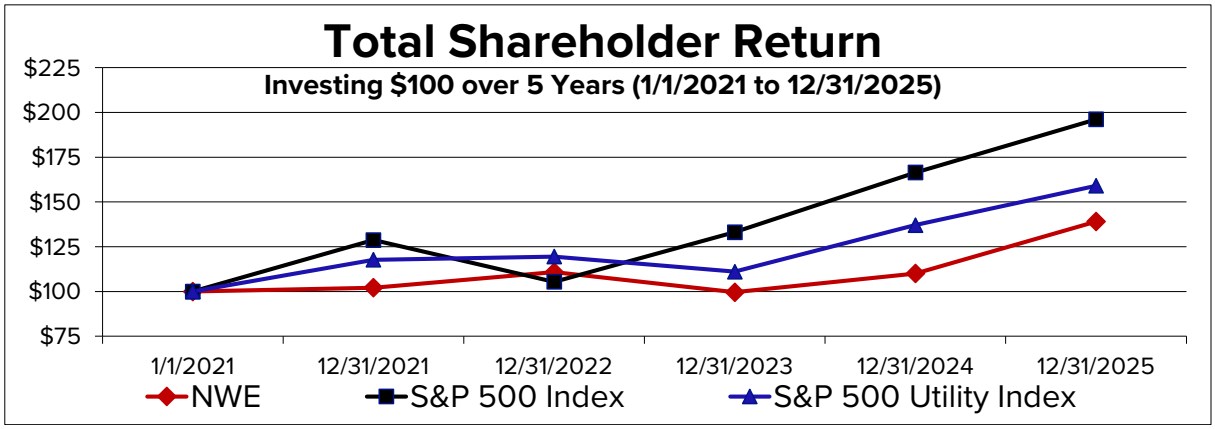
Committees: Audit (Chair), Nominating and Governance

Director since October 2019

FINANCIAL HIGHLIGHTS

	2025	2024	Change
Utility Margin ($000's) *	$1,200,804	$1,080,082	11.2%
Net Income ($000's)	$181,092	$224,111	-19.2%
GAAP Earnings per Diluted Share	$2.94	$3.65	-19.5%
Return on Average Equity	6.3%	8.0%	-21.3%
Dividends Declared per Common Share	$2.64	$2.60	1.5%
Dividend Payout Ratio	89.8%	71.2%	26.1%
Total Debt to Capitalization Ratio	54.5%	52.0%	4.7%
Total Capital Investment ($000's)**	$588,921	$547,927	7.5%
Number of Customers	850,300	787,000	8.0%
Number of Employees	1,667	1,585	5.2%
Retail Volumes Delivered (000's)			
Electric (megawatt hours)	10,630	10,721	-0.8%
Natural Gas (dekatherms)	35,854	31,343	14.4%

* Utility Margin is considered a non-GAAP financial measure
** PP&E Additions plus AFUDC Credit from the cash flow statement plus change in capital expenditures included in trade accounts payable



TOTAL SHAREHOLDER RETURN

The following table assumes $100 was invested in our common stock on Jan. 1, 2021 and compares the share price performance with the S&P Utility Index and the S&P 500 Index for the years ending Dec. 31, 2021, 2022, 2023, 2024 and 2025. Total return is computed assuming reinvestment of dividends.

	1/1/2021	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025
NorthWestern Energy	$100.00	$102.08	$110.77	$99.55	$110.01	$139.04
S&P 500 Index	$100.00	$128.71	$105.40	$133.10	$166.40	$196.16
S&P Utility Index	$100.00	$117.67	$119.51	$111.05	$137.07	$159.06

CREDIT RATINGS

		Moody's	S&P	Fitch
NWEG (Hold-Co.)	Issuer	-	BBB	BBB
	Secured	-	-	-
	Unsecured	-	-	BBB
	Outlook	-	Positive	Stable
NW Corp. (MT Op.-Co.)	Issuer	Baa2	BBB	BBB
	Secured	A3	A-	A-
	Unsecured	Baa2	-	BBB+
	Outlook	Stable	Positive	Stable
NWEPS (SDNE Op.-Co.)	Issuer	Baa2	BBB	BBB
	Secured	A3	A-	A-
	Unsecured	-	-	BBB+
	Outlook	Stable	Stable	Stable

Investor Information

CORPORATE SUPPORT OFFICE

NorthWestern Energy
3010 W. 69th Street | Sioux Falls, SD 57108
Phone: (605) 978-2900 | Fax: (605) 978-2910
Website: www.northwesternenergy.com

INVESTOR RELATIONS

Phone: (605) 978-2945
Email: investor.relations@northwestern.com

MARKET INFORMATION AS OF DECEMBER 31, 2025

Nasdaq

Ticker Symbol:	NWE
Year-end Closing Price:	$64.54
Shares Outstanding:	61.4 million
Market Capitalization:	$4.0 billion
Dividend Yield:	4.1%

COMMON STOCK DIVIDENDS

In February 2026 we increased our quarterly dividend to 67 cents per share. Anticipated record and payment dates for 2026 are as follows:

RECORD DATE	PAYMENT DATE
March 13	March 31
June 15	June 30
September 15	September 30
December 15	December 31

REGISTRAR, TRANSFER AGENT AND DIVIDEND DISBURSING AGENT

Questions regarding stock transfer, lost certificates and dividend checks should be referred to:

Computershare
c/o Shareholder Services
150 Royall St.
Canton, MA 02021
Telephone: 1+ (800) 736-3001
Internet: www.computershare.com

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

NorthWestern Energy offers a dividend reinvestment and direct stock purchase plan as a service to both new investors and current shareholders.
Information is available on our website at NorthWesternEnergy.com/dividend

2026 VIRTUAL ANNUAL MEETING

April 30, 2026
10:00 a.m. Mountain Daylight Time
www.virtualshareholdermeeting.com/NWE2026

INDEPENDENT REGISTERED ACCOUNTING FIRM

Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

BROKERAGE ACCOUNTS

Stock purchased and held for a shareholder by a broker is listed in the broker's name, or "street name." Annual and quarterly reports, proxy material and dividend payments are sent to shareholders by their broker. Questions should be directed to the broker.

FINANCIAL PUBLICATIONS

The company reports details concerning its operation and other matters periodically to the Securities and Exchange Commission on Form 8-K, Form 10-Q and Form 10-K. These publications are available on our website at NorthWesternEnergy.com/SECfilings. **You may request a copy of these publications, free of charge, by contacting Investor Relations.**

CORPORATE GOVERNANCE INFORMATION

Corporate governance information, including our Corporate Governance Guidelines, Code of Conduct and Ethics, Code of Ethics for CEO and Senior Financial Officers, and charters for the Committees of our Board of Directors, is available on our website at NorthWesternEnergy.com/CorpGov

This Annual Report is prepared primarily for the information of our shareholders and is not given in connection with the sale of any security or offer to sell or buy any security.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

OR

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

For the transition period from to

Commission File Number: 000-56598

NorthWestern® Energy

NORTHWESTERN ENERGY GROUP, INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

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

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. Yes ☐ No ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to the previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

The aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant was $3,149,159,359 computed using the last sales price of $51.30 per share of the registrant's common stock on June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 6, 2026, 61,443,621 shares of the registrant's common stock, par value $0.01 per share, were outstanding.

Documents Incorporated by Reference

Certain sections of our Proxy Statement for the 2026 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report on Form 10-K regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Annual Report, relating to our current expectations of future financial performance, continued growth, changes in economic conditions or capital markets, changes in customer usage patterns and preferences, and statements relating to our pending merger with Black Hills Corporation are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

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

- risks relating to the pending merger transaction pursuant to that certain Agreement and Plan of Merger dated August 18, 2025 (Merger Agreement) between NorthWestern, Black Hills, and River Merger Sub Inc., a Delaware corporation and direct wholly owned subsidiary of Black Hills (Merger Sub), including, among others, (1) the risk of delays in consummating the pending merger 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 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 or final rates not consistent with a reasonable ability to earn our allowed returns, adverse rulings on our ability to serve large-load customers, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, and wildfire damages in excess of liability insurance coverage, could have a material effect on our liquidity, results of operations and financial condition;
- the impact of extraordinary external events and natural disasters, such as a wide-spread or global pandemic, geopolitical events, earthquake, flood, drought, lightning, weather, wind, and fire, could have a material effect on our liquidity, results of operations and financial condition;
- acts of terrorism, cybersecurity attacks, data security breaches, or other malicious acts that cause damage to our generation, transmission, or distribution facilities, information technology systems, or result in the release of confidential customer, employee, or Company information;

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

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

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

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

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

GLOSSARY

Accounting Standards Codification (ASC) - The single source of authoritative nongovernmental GAAP, which supersedes all existing accounting standards.

Allowance for Funds Used During Construction (AFUDC) - A regulatory accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Asset Retirement Obligations (ARO) - The legal obligations associated with retirement of a long-lived asset.

Base-Load - The minimum amount of electric power or natural gas delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time usually is not temperature sensitive.

Base-Load Capacity - The generating equipment normally operated to serve loads on an around-the-clock basis.

BGGS - The Bob Glanzer Generating Station located near Huron, South Dakota, a 58 MW natural gas fired electric generation facility.

Black Hills - Black Hills Corporation.

Bright Horizon Energy Corporation (Bright Horizon Energy) - The new corporate name that Black Hills will assume following the completion of the Merger Agreement.

Capacity - The amount represents the maximum output of electricity a generator can produce and is related to peak demand. We must maintain a level of available capacity sufficient to meet peak demand with a sufficient reserve.

Colstrip - A jointly owned sub-bituminous coal fired electric generation facility located near Colstrip, Montana, of which, as of January 1, 2026, we have a 55 percent ownership of Units 3 & 4.

Commercial Customers - Consists primarily of main street businesses, shopping malls, grocery stores, gas stations, bars and restaurants, professional offices, hospitals and medical offices, motels, and hotels.

Cushion Gas - The natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.

DGGS - The Dave Gates Generating Station at Mill Creek, Montana, a 150 MW natural gas fired electric generation facility.

Environmental Protection Agency (EPA) - A Federal agency charged with protecting the environment.

Federal Energy Regulatory Commission (FERC) - The Federal agency that has jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.

Franchise - A special privilege conferred by a unit of state or local government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have franchises for utility service granted by state or local governments.

GAAP - Accounting principles generally accepted in the United States of America.

Greenhouse Gas (GHG) - Gas that traps heat in the atmosphere.

Hedging - Entering into transactions to manage various types of risk (e.g. commodity price risk).

Industrial Customers - Consists primarily of manufacturing and processing businesses that turn raw materials into products.

Integrated Resource Plan (IRP) - A plan that is presented to a regulatory commission. The plan identifies resource needs, known and expected risks, as well as key variables to be used in evaluating energy supply resources.

Lignite Coal - The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It has high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis.

Mercury Air Toxics Standard (MATS) - This standard limits the amount of mercury and other toxic emissions from power plants.

Montana Department of Environmental Quality (MDEQ) - The state agency that works to enhance the health of Montana's natural environment and the vitality of the state's fish, wildlife, cultural, and historic resources.

Midcontinent Independent System Operator (MISO) - MISO is a nonprofit organization created in compliance with FERC as a regional transmission organization, to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing the energy markets, managing transmission constraints, managing the day-ahead, real-time and financial transmission rights markets, and managing the ancillary market.

Midwest Reliability Organization (MRO) - MRO is one of eight regional electric reliability councils under NERC.

Montana Public Service Commission (MPSC) - The state agency that regulates public utilities doing business in Montana.

Nameplate Capacity - The intended full-load sustained output of a generating facility. Nameplate capacity is the number registered with authorities for classifying the power output of a power station usually expressed in MWs.

Nebraska Public Service Commission (NPSC) - The state agency that regulates public utilities doing business in Nebraska.

Net Operating Loss (NOL) - net operating loss as it relates to Federal and State income tax law and results from tax-deductible expenses exceeding taxable revenues for a taxable year.

North American Electric Reliability Corporation (NERC) - NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States. NERC's major responsibilities include developing standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.

North Plains Connector (NPC) - A 3,000-megawatt, 415-mile high-voltage direct current transmission line to be constructed with endpoints near Bismark, North Dakota, and Colstrip, Montana.

NorthWestern Colstrip 370Pu, LLC (NW Colstrip 370) - a direct, wholly-owned FERC regulated subsidiary of NorthWestern Energy Group, which has a 25 percent ownership interest in Colstrip Units 3 & 4.

NorthWestern Corporation (NW Corp) - A direct, wholly-owned regulated utility subsidiary of NorthWestern Energy Group providing both electric and natural gas services in Montana and electric services to Yellowstone National Park.

NorthWestern Energy Group, Inc. - The Company; Also known as NorthWestern Energy Group.

NorthWestern Energy Public Service Corporation (NWE Public Service) - A direct, wholly-owned regulated utility subsidiary of NorthWestern Energy Group providing both electric and natural gas services in South Dakota and natural gas services in Nebraska.

Open Access - Non-discriminatory, fully equal access to transportation or transmission services offered by a pipeline or electric utility.

Open Access Transmission Tariff (OATT) - The OATT, which is established by the FERC, defines the terms and conditions of point-to-point and network integration transmission services offered by us, and requires that transmission owners provide open, non-discriminatory access on their transmission system to transmission customers.

Peak Load - A measure of the maximum amount of energy delivered at a point in time.

Power Cost and Credit Recovery Mechanism (PCCAM) - A tracker used in our Montana jurisdiction to track, for recovery through utility rates, the cost of power purchased and fuel used to generate electricity.

Qualifying Facility (QF) - As defined under the Public Utility Regulatory Policies Act of 1978 (PURPA), a QF sells power to a regulated utility at a price agreed to by the parties or determined by a public service commission that is intended to be equal to that which the utility would otherwise pay if it were to generate its own power or buy power from another source.

Reserve Margin - The difference between available capacity and peak demand used in system planning to ensure adequate power supply. A positive percentage indicates the electric system has excess capacity while a negative percentage indicates the electric system is unable to meet peak demand without using market resources.

Securities and Exchange Commission (SEC) - The U.S. agency charged with protecting investors, maintaining fair, orderly and efficient markets and facilitating capital formation.

Secured Overnight Financing Rate (SOFR) - A broad measure of the cost of borrowing cash overnight collateralized by Treasury securities.

South Dakota Public Utilities Commission (SDPUC) - The state agency that regulates public utilities doing business in South Dakota.

Southwest Power Pool (SPP) - A nonprofit organization created in compliance with FERC as a regional transmission organization to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. SPP also serves as a regional electric reliability entity under NERC.

Tariffs - A collection of the rate schedules and service rules authorized by a federal or state commission. It lists the rates a regulated entity will charge to provide service to its customers as well as the terms and conditions that it will follow in providing service.

Transmission - The flow of electricity from generating stations and interconnections with other systems over high voltage lines to substations. The electricity then flows from the substations into a distribution network.

Western Area Power Administration (WAPA) - A federal power-marketing administration and electric transmission agency established by Congress.

Western Electricity Coordination Council (WECC) - WECC is one of eight regional electric reliability councils under NERC.

YCGS - The Yellowstone County Generating Station is a 175 MW natural gas fired facility, located near Laurel, Montana.

Measurements:

Billion Cubic Feet (Bcf) - A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

British Thermal Unit (Btu) - A basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

Degree-Day - A measure of the coldness / warmness of the weather experienced, based on the extent to which the daily mean temperature falls below or above 65 degrees Fahrenheit.

Dekatherm - A measurement of natural gas; ten therms or one million Btu.

Kilovolt (kV) - A unit of electrical power equal to one thousand volts.

Megawatt (MW) - A unit of electrical power equal to one million watts or one thousand kilowatts.

Megawatt Hour (MWH) - One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.

ITEM 1. BUSINESS

OVERVIEW

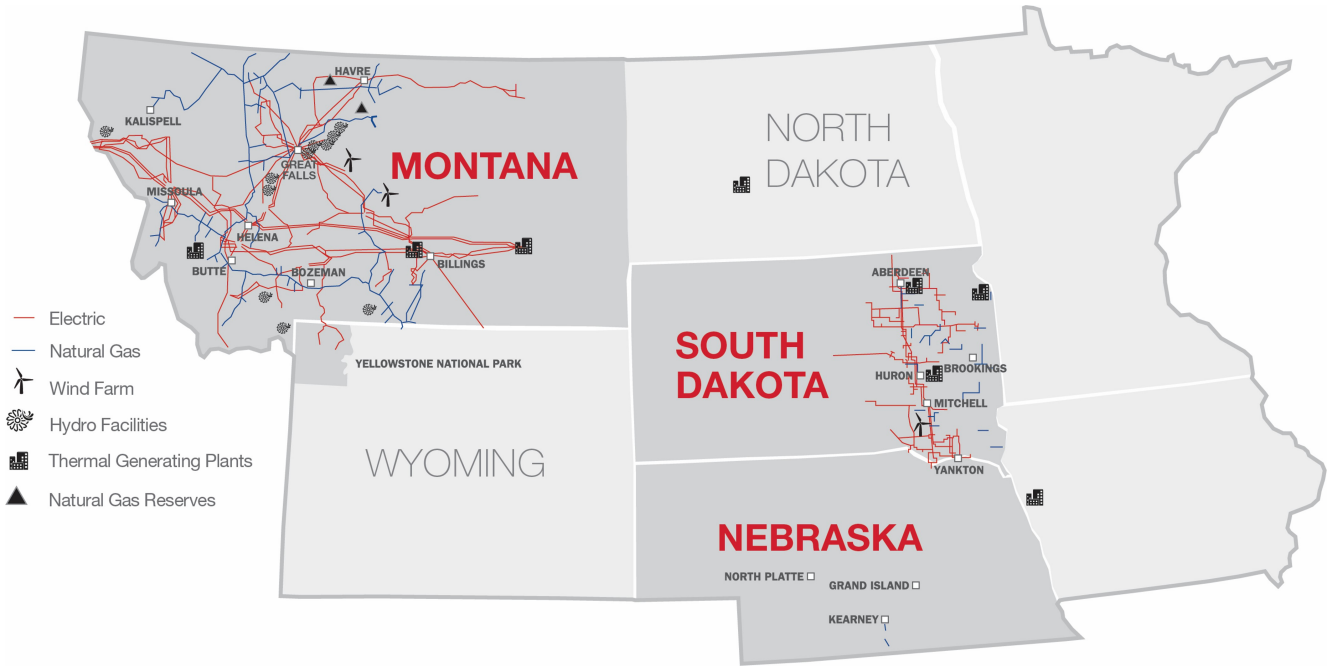
NorthWestern Energy - Delivering a Bright Future

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.

On August 18, 2025, we entered into the Merger Agreement with Black Hills and Merger Sub, that provides for an all-stock merger of equals between NorthWestern and Black Hills (the Merger). The Merger Agreement provides for Merger Sub to merge with and into NorthWestern, with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of Black Hills, which would assume the new corporate name of Bright Horizon Energy as the resulting parent company of the combined corporate group. The Merger will combine the strengths of both companies, resulting in an organization with greater scale, financial stability, and operational expertise. It is designed to create a stronger, more resilient energy company focused on delivering safe, reliable, and affordable energy solutions to customers. Pursuant to the Merger Agreement, at the effective time of the Merger, each share of common stock of NorthWestern issued and outstanding as of immediately prior to closing will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of common stock of Black Hills, par value $1.00 per share (Black Hills Common Stock). See Note 3 - Pending Merger with Black Hills Corporation to the Consolidated Financial Statements included herein for additional information regarding this pending Merger.

We manage our businesses by the nature of services provided, and operate principally in two operating segments: electric utility operations and natural gas utility operations. Our electric utility operations include the generation, purchase, transmission and distribution of electricity, and our natural gas utility operations include the production, purchase, transmission, storage, and distribution of natural gas. Our customer base consists of a mix of residential, commercial, and diversified industrial customers.

Our electric and natural gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of our largest customers is not reasonably likely to have a material adverse effect on our financial condition. Our utility operations are seasonal and weather patterns can have a material impact on operating performance. Consumption of electricity is often greater in the summer and winter months for cooling and heating, respectively. Because natural gas is used primarily for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season.



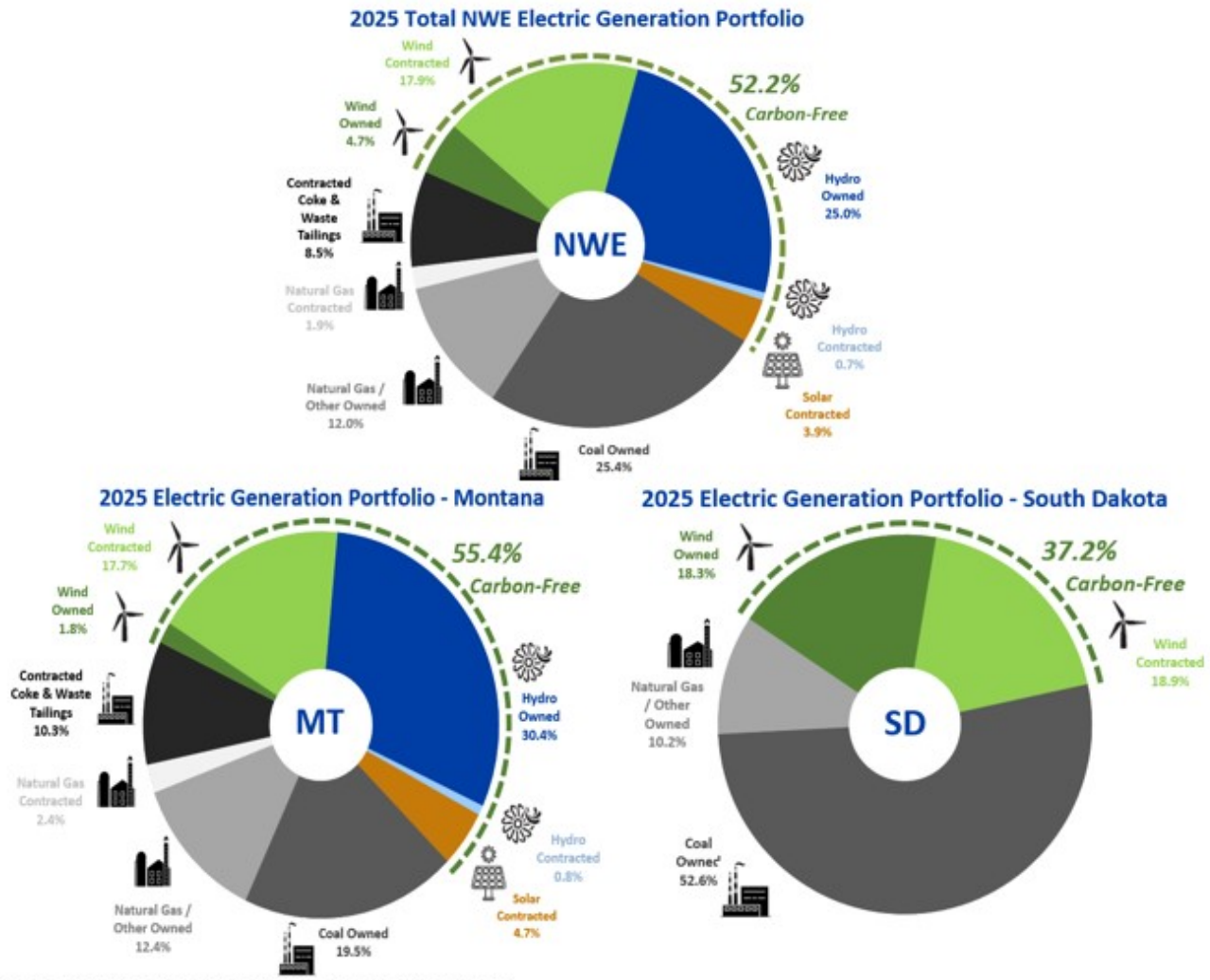
We have a social responsibility to our customers to deliver reliable energy at an affordable price. Our reliability standards and results are typically in the first or second quartile compared to our peers and our typical residential bills are significantly lower than the national average. We are engaged with the communities we serve, hosting town meetings to provide updates on important matters relating to both NorthWestern and our residents. For our employees, we offer a career with competitive pay and great benefits, providing a balance between work and life. We have been recognized by Newsweek as one of the "Great Places to Work" three years in a row.

Over time, we have increased our environmental sustainability efforts and our access to carbon-free energy resources. In February 2022, we made a commitment to achieving Net-Zero by the year 2050 for Scope 1 and Scope 2 carbon and methane emissions. Our Scope 1 emissions are primarily from owned electric generation plants, fugitive emissions from our natural gas production, gathering, transmission and distribution systems and company owned transportation fleet. Our Scope 2 emissions are primarily from the electric and natural gas utilized to heat, cool and power our offices, warehouses and other facilities.

We currently own a mix of clean and carbon-free energy resources balanced with traditional energy sources that are necessary for us to deliver affordable and reliable electricity to our customers 24/7. In 2025, approximately 52 percent of our electric portfolio, from owned and long-term resources, was carbon-free, compared to approximately 41 percent (Source: U.S. Energy Information Administration, Annual Energy Review, Electricity Net Generation: Electric Power Sector) for the total U.S. electric power industry in 2024. We do not receive all of the related Renewable Energy Credits (RECs) from our contracted electric supply resources. The owner of the RECs claims the renewable attributes of the energy. Our resource mix does not represent the actual energy delivered to our customers. Market purchases and sales fill the gaps between customer demand and economic dispatch of our supply portfolio resources.

In 2025, we completed construction of the 175 MW YCGS electric generation facility and in 2026, we expect to complete construction of Aberdeen Generating Station Units 3 & 4, a 33 MW natural gas fired electric generating facility located in Aberdeen, South Dakota. On January 1, 2026, we acquired an additional 592 MW of ownership interest in Colstrip Units 3 & 4. As discussed further below, in order to meet the SPP's additional accredited capacity needs by 2030, 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. While still striving to meet our environmental goal of Net Zero by 2050, these generation facilities are needed to support our efforts to provide reliability and affordability to our customers. Since 2011, we have added 1,096 MW of carbon-free generation (both owned and long-term contract) in Montana and South Dakota. We believe that technological advancements, along with decreasing costs of carbon-free generation and the regionalization of intermittent generation, will significantly contribute to our Net-Zero goal. The pace of transition to Net-Zero will depend on the timing of technological advancements, costs, and retirement of our existing coal fleet.

We are committed to conducting business with integrity, while ensuring transparency and accountability, and meeting our responsibilities to all our stakeholders. We adhere to a strict code of ethics regarding corporate governance. Our Code of Conduct and Ethics applies to all employees, board members, vendors and contractors, with additional Code of Ethics for the Chief Executive Officer and Senior Financial Officers concerning financial reporting and other related matters.



Based on MWh's supplied from owned & long-term contracted resources.

Contracted energy from Colstrip Energy Limited Partners (CELP), Yellowstone Energy Limited Partners (YELP) as well as a majority of the contracted wind, hydro and solar are federally mandated Qualifying Facilities, a defined under the Public Utility Regulatory Policies Act of 1978 (PURPA).

NorthWestern does not own all the renewable energy certificates (RECs) generated by contracted resources .Accordingly, we cannot represent that 100% of carbon-free energy in the portfolio was delivered to our customers.

MONTANA ELECTRIC OPERATIONS

Our regulated electric utility business in Montana, which is primarily conducted through NW Corp, includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73 percent of Montana's land area. During 2025, we delivered electricity to approximately 440,700 customers in 225 communities and their surrounding rural areas, 13 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2025, by category, residential, commercial, industrial, and other sales accounted for approximately 46%, 46%, 5%, and 3%, respectively, of our Montana retail electric utility revenue.

Transmission and Distribution

Our electric system is composed of high voltage transmission lines and low voltage distribution lines as follows:

Electric Transmission Lines	
Miles of 500 kV	497
Miles of 230 kV	988
Miles of 161 kV	1,184
Miles of 115 kV and lower voltage	3,927
Total Miles of Electric Transmission Lines	**6,596**
Electric Distribution Lines	
Miles of overhead line	13,263
Miles of underground line	5,683
Total Miles of Electric Distribution Lines	**18,946**
Total Transmission and Distribution Substations	**397**

In addition to delivering energy to distribution systems to serve customers, we also transmit electricity for nonregulated entities owning generation, and utilities, cooperatives, and power marketers serving the Montana electricity market. Our total control area peak demand reached a peak of approximately 1,976 MWs on February 13, 2025. Our control area average demand for 2025 was approximately 1,345 MWs per hour, with total energy delivered of approximately 11.78 million MWHs.

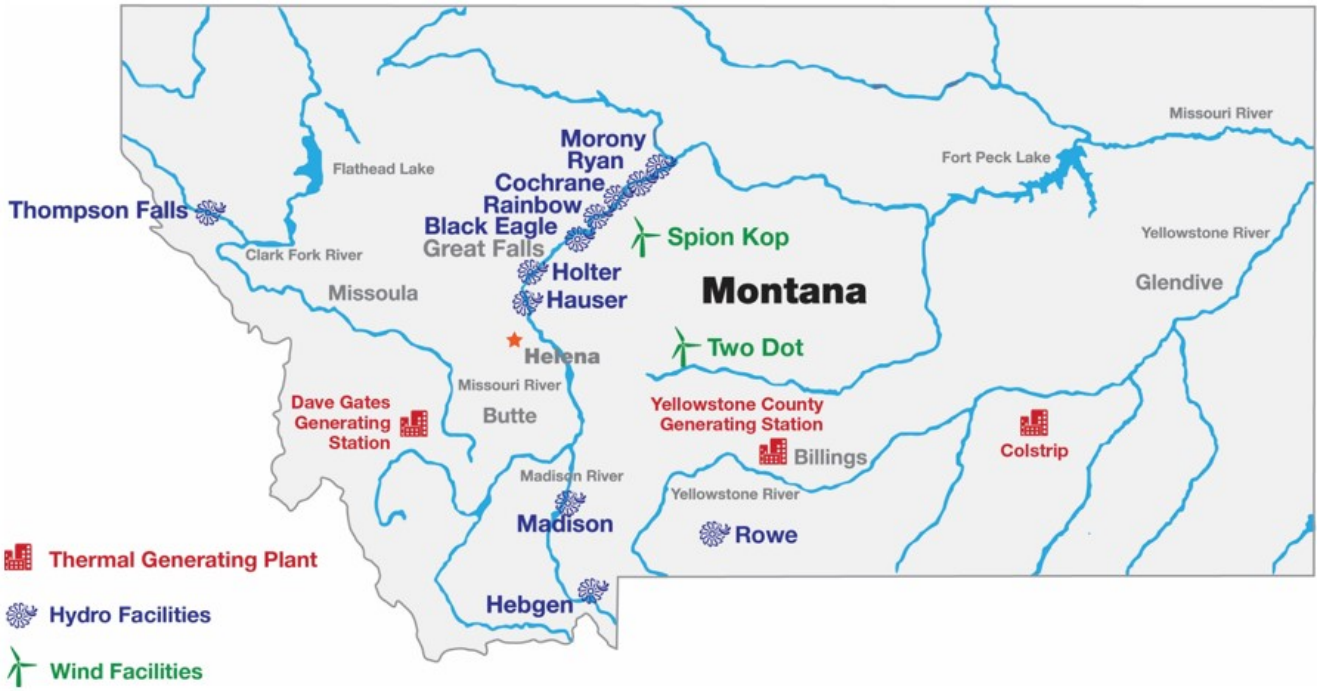
Our transmission system is directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; WAPA; and Montana Alberta Tie. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among all major electric systems in the west interconnecting with the winter-peaking northern and summer-peaking southern regions of the western power system. We provide wholesale transmission service and firm and non-firm transmission services for eligible transmission customers pursuant to our FERC OATT.

Electric Supply

Our annual retail electric supply load requirement averages approximately 767 MWs per day, with a peak load of approximately 1,300 MWs, and are supplied by owned and contracted resources and market purchases with multiple counterparties.

In 2025, our owned generation resources generated electric supply representing approximately 67 percent of our retail load. We expect that our owned generation resources will generate electric supply representing approximately 95 percent of our forecasted retail load for 2026. The increase relative to the prior year is due to the acquisition of additional interests in Colstrip Units 3 & 4 from Avista. In addition, we have contracts with QFs totaling 569 MWs of nameplate capacity, including 107 MWs from waste petroleum coke and waste coal, 268 MWs from wind, 17 MWs from hydro, and 177 MWs from solar projects. We have several other long-term power purchase agreements including contracts for 135 MWs nameplate capacity from wind generation, 310 MWs from unspecified resources, 52 MWs of natural gas generation, and 13 MWs of hydro supply. On average, our owned and long-term contracted resources are expected to provide enough energy to meet our retail energy load requirements in 2026. Load requirements during peak demand in excess of our owned and long-term contracted resources will be satisfied with market purchases. Our owned and contracted resources will be economically dispatched to meet load requirements and any excess supply will be sold into the market.

Owned Generation Facilities



Details of these generating facilities are described in the following tables.

Hydro Facilities	COD	River Source	FERC License Expiration	Owned MW
Black Eagle	1927	Missouri	2040	25
Cochrane	1958	Missouri	2040	64
Hauser	1911	Missouri	2040	22
Holter	1918	Missouri	2040	56
Madison	1906	Madison	2040	12
Morony	1930	Missouri	2040	49
Mystic (Rowe Dam)	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	64
Ryan	1915	Missouri	2040	72
Thompson Falls	1915/1995	Clark Fork	2026[1]	94
Total[2]				**470**

(1) We are in the process of relicensing the Thompson Falls hydro facility. The FERC extended our current license for 2026, and we anticipate that they will continue to extend on an annual basis until our relicensing proceeding is complete.
(2) The Hebgen facility (0 MW net capacity) is excluded from the figures above. These are run-of-river dams except for Mystic, Cochrane, Ryan and Morony.

Other Facilities	Fuel Source	Ownership Interest	Owned MW
Colstrip Units 3 & 4, located near Colstrip in southeastern Montana[1]	Sub-bituminous coal	55%	814
DGGS, located near Anaconda, Montana	Natural Gas & Liquid Fuel	100%	150
YCGS, located near Laurel, Montana	Natural Gas	100%	175
Spion Kop Wind, located in Judith Basin County in Montana	Wind	100%	40
Two Dot Wind, located in Wheatland County in Montana	Wind	100%	11
Total			1,190

(1) We have three separate ownership interests in Colstrip facility, a 30 percent ownership interest in Unit 4, a 15 percent ownership interest in Colstrip Units 3 & 4, and a 25 percent ownership interest in Colstrip Units 3 & 4, totaling to a 55 percent ownership interest in Colstrip Units 3 & 4.

Colstrip Units 3 & 4 provide base-load supply and are operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. Associated with our 30 percent ownership interest in Colstrip Unit 4, we have a reciprocal sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15 percent of the respective combined output and is responsible for 15 percent of the respective operating and construction costs, regardless of whether a particular cost is specified to Colstrip Unit 3 or 4. However, each party is responsible for its own fuel-related costs. On January 1, 2026, we acquired an additional 40 percent ownership interest in Colstrip Units 3 & 4. This includes the acquisition of ownership interests previously owned by Avista Corporation (Avista) (222 MW) and Puget Sound Energy (Puget) (370 MW) that brought our total share of Colstrip Units 3 & 4 up to 814 MW, or 55 percent of the plant capacity. We have a coal supply agreement to supply fuel from adjacent coal reserves for our ownership interests in Colstrip Units 3 & 4 that is effective through 2033. The 222 MW interest in Colstrip Units 3 & 4 acquired from Avista is owned by NW Corp and is included in our MPSC regulated supply portfolio. The 370 MW interest in Colstrip Units 3 & 4 acquired from Puget is owned by NW Colstrip 370. This resource is not included within the MPSC regulated resource supply portfolio at this time. We expect our future opportunity to serve growing utility customer demand, including large-load customers, may be supported by this resource.

Resource Planning

Resource planning is an important function necessary to meet our customers' future energy needs and is used to guide resource acquisition activities. Our Draft 2026 IRP is publicly available and is scheduled to be filed with the Commission in April 2026. This IRP is our first plan developed under the 2023 Montana administrative rules, which transitioned the planning process from a traditional resource adequacy focus to an integrated evaluation of generation, transmission, fuel supply, and reliability. Our previous resource plan was filed with the MPSC in April 2023.

While 2026 capacity adequacy is maintained due to the recent additions of YCGS and Avista's 222 MW share of Colstrip Units 3 & 4, the 2026 IRP identifies emerging capacity needs beginning in 2027 driven by load growth, capacity contract expirations, and resource retirements. Consistent with regional practice, NorthWestern evaluates resource adequacy through the Western Resource Adequacy Program, which establishes planning reserve margin requirements based on probabilistic reliability metrics and seasonal system conditions.

In addition to our responsibility to meet peak demand, national NERC reliability standards continue to require sufficient dispatchable generation capable of increasing or decreasing output to manage system variability, including the growing demand of intermittent generation such as wind and solar. Our generation portfolio remains a balanced mix of energy and capacity resources having different operating characteristics and fuel sources designed to reliably serve retail customers at the lowest possible cost while maintaining reliability.

Western Energy Imbalance Market

We entered the Western Energy Imbalance Market (EIM), operated by the California Independent System Operator, on June 16, 2021. We have EIM transfer capability with PacifiCorp, Idaho Power Company, Bonneville Power Administration, Avista Corp, and Tacoma Power.

SOUTH DAKOTA ELECTRIC OPERATIONS

Our South Dakota electric utility business, which is conducted through NWE Public Service, operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties. We provide retail electricity to more than 65,600 customers in 118 communities in South Dakota. In 2025, by category, residential, commercial and other sales accounted for approximately 39%, 59%, and 2%, respectively, of our South Dakota retail electric utility revenue.

Transmission and Distribution

Our electric system includes high voltage transmission and low voltage distribution lines as follows:

Electric Transmission Lines	
Miles of 345 kV	25
Miles of 230 kV	18
Miles of 115 kV and lower voltages	1,301
Total Miles of Electric Transmission Lines	**1,344**
Electric Distribution Lines	
Miles of overhead line	1,630
Miles of underground line	756
Total Miles of Electric Distribution Lines	**2,386**
Total Transmission and Distribution Substations	**123**

Our South Dakota system is interconnected with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We also have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative.

We are a member in the SPP, with our transmission facilities residing in zone 19 of the SPP footprint. Each year, we review all new or modified transmission assets and transfer functional control of assets that qualify under the SPP Tariff to the SPP. This annual update goes into effect on April 1st each year. To date, we have transferred control of 333 line miles of 115 kV facilities and over 158 line miles of 69 kV facilities. While we have transferred functional control of these facilities to the SPP, they are still owned by us and reflected in the table above. Along with SPP, our South Dakota facilities have ties to MISO. We have grandfathered agreements in MISO, which provide us the access to move the power from the Coyote, Big Stone, and Neal power plants to our customers. Along with operating the transmission system, SPP also coordinates regional transmission planning for all of its members on an annual basis through its Integrated Transmission Planning (ITP) process. Our annual participation in the ITP process includes model development, system needs assessment, and solution development to address identified needs.

Electric Supply

Our annual retail electric supply load requirements average approximately 188 MWs, with a peak load of approximately 325 MWs, and are supplied by owned and contracted resources and market purchases. We use market purchases and peaking generation to provide peak supply in excess of our base-load capacity. We are a member of the SPP. As a market participant in SPP, we buy and sell wholesale energy and reserves in both day-ahead and real-time markets through the operation of a single, consolidated SPP balancing authority. We and other SPP members submit into the SPP market both offers to sell our generation and bids to purchase power to serve our load. SPP optimizes next-day and real-time generation dispatch across the region and provides participants with greater access to economic energy. Marketing activities in SPP are handled for us by a third-party provider acting as our agent.

Electric supply resources include 211 MWs from jointly owned coal plants and 118 MWs from two natural gas-fired plants. Additional resources include several peaking units and an 80 MW wind facility. We also purchase the output of four wind projects, three of which are QFs, under power purchase agreements. Actual output for our wind resources varies based upon weather conditions.

Owned Generation Facilities



Details of our generating facilities are described further in the following chart:

Generation Facilities	Fuel Source	Ownership Interest	Owned MW
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	23.4%	111
Aberdeen Generating Unit No. 2, located near Aberdeen, South Dakota	Natural gas & Liquid Fuel	100.0%	60
Beethoven Wind Project, located near Tripp, South Dakota	Wind	100.0%	80
BGGS, located near Huron, South Dakota	Natural Gas	100.0%	58
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	8.7%	56
Coyote Electric Generating Station, located near Beulah, North Dakota	Lignite coal	10.0%	43
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas	100.0%	12
Total			**420**

The Big Stone, Coyote and Neal plants are owned jointly with unaffiliated parties. Each of the jointly owned plants is subject to a joint management structure, and we are not the operator of any of these plants. Based on our ownership interest, we are entitled to a proportionate share of the capacity of our jointly owned plants and are responsible for a proportionate share of the operating costs.

The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal Unit No. 4 and Big Stone receive their fuel supply via rail. The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs.

Resource Planning

We maintain an integrated resource planning process that includes forecasts of customer energy usage and evaluates a range of options to provide for the economic, reliable, and timely supply of energy. We regularly update our load forecasts to reflect changes in customer demand, industrial growth, and regional planning requirements, and we assess future generating capacity needs on an ongoing basis. In September 2024, we submitted an updated 2024 IRP to the South Dakota Public Utilities Commission that incorporates updated load forecasts, revised planning reserve margin requirements, updated resource cost and performance assumptions, and an evaluation of a range of resource portfolios over a twenty-year planning horizon.

Consistent with the 2024 IRP, we are replacing older generation resources at the Aberdeen Generating Station, with construction of Aberdeen Generating Station Units 3 & 4 underway and an expected in-service date in 2026. This project is expected to provide approximately 33 MW of nameplate capacity at a total projected cost of approximately $65.0 million, of which approximately $29.0 million is expected to be incurred in 2026.

The SPP has recently updated its resource accreditation and Planning Reserve Margin (PRM) requirements in response to growing reliability concerns. As a result, SPP is requiring additional accredited capacity by 2030 to meet the updated PRM targets. In October 2025, we submitted a project with the SPP under their Expedited Resource Adequacy Study program for the construction of a 131 MW natural gas generating facility located in Aberdeen, South Dakota, to meet regional capacity needs by 2030. Anticipated costs for this project are approximately $300.0 million.

NATURAL GAS OPERATIONS

Montana

Our regulated natural gas utility business in Montana, which is conducted through NW Corp, includes production, storage, transmission and distribution. During 2025, we distributed natural gas to approximately 249,400 customers in 123 Montana communities over a system that consists of approximately 5,900 miles of underground distribution pipelines. We also serve a smaller distribution company that provides service to approximately 1,417 customers. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 51 Bcf during the year ended December 31, 2025.

Miles of Natural Gas Transmission	**2,133**
Miles of Natural Gas Distribution	**5,939**
City Gate Stations	**134**

We have connections in Montana with five major, unaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, Black Hills Energy, and Many Islands Pipeline. Thirteen compressor sites provide more than 51,400 horsepower on the transmission line and an additional 16,586 horsepower at our storage fields, capable of moving more than 400,000 dekatherms per day. In addition, we own and operate two transmission pipelines through our subsidiaries, Canadian-Montana Pipe Line Corporation and Havre Pipeline Company, LLC.

Natural gas is used primarily for residential and commercial heating, and as fuel for three electric generating facilities. The demand for natural gas largely depends upon weather conditions. Our Montana retail natural gas supply requirements for the year ended December 31, 2025, were approximately 22.8 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2025, were approximately 10.8 Bcf. We have contracted with several major

producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts, short-term market purchases and owned production. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in significant natural gas producing regions in the United States, primarily the Rocky Mountains (Colorado), Montana, and Alberta, Canada.

Owned Production and Storage - Since 2010, we have acquired gas production and gathering system assets as a part of an overall strategy to provide rate stability and customer value: as we own these assets, which are regulated, our customers are better protected from potential price spikes in the market. As of December 31, 2025, these owned reserves totaled approximately 25.3 Bcf and are estimated to provide approximately 2.76 Bcf in 2026, or approximately 14 percent of our expected annual retail natural gas load in Montana. In addition, we own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.85 Bcf and maximum aggregate daily deliverability of approximately 194,000 dekatherms.

South Dakota and Nebraska

Through NWE Public Service, we provide natural gas to approximately 51,200 customers in 82 South Dakota communities and approximately 43,400 customers in 4 Nebraska communities. In South Dakota, we also transport natural gas for nine gas-marketing firms and three large end-user accounts. In Nebraska, we transport natural gas for four gas-marketing firms and one large end-user account. We delivered approximately 31.0 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 3.8 Bcf of third-party transportation volume on our Nebraska distribution system during 2025.

Miles of Natural Gas Transmission	**55**
Miles of Natural Gas Distribution - South Dakota	**1,853**
Miles of Natural Gas Distribution - Nebraska	**836**

Our South Dakota natural gas supply requirements for the year ended December 31, 2025, were approximately 6.3 Bcf. We contract with a third party under an asset management agreement to manage transportation and storage of supply to minimize cost and price volatility to our customers. In Nebraska, our natural gas supply requirements for the year ended December 31, 2025, were approximately 4.1 Bcf. We contract with a third party under an asset management agreement that includes pipeline capacity, supply, and asset optimization activities. To supplement firm gas supplies in South Dakota and Nebraska, we contract for firm natural gas storage services to meet the heating season and peak day requirements of our customers.

Municipal Natural Gas Franchise Agreements

We have municipal franchises to provide natural gas service in the communities we serve in Nebraska and South Dakota. The terms of the franchises vary by community. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy generally is to seek renewal or extension of a franchise in the last year of its term. We continue to serve those customers while we obtain formal renewals. In the 2025 Montana legislative session, new language was enacted eliminating the requirement for gas franchise agreements. Under this law, utility providers may construct and maintain natural gas lines within the public rights-of-way without obtaining a franchise agreement. Two of our South Dakota franchises and two of our franchises in Nebraska, which account for approximately 32,613 or 34 percent of our South Dakota and Nebraska natural gas customers, are scheduled to reach the end of their fixed term during the next five years. We do not anticipate termination of any of these franchises.

GOVERNMENT REGULATION

Our provision of utility service is regulated by the MPSC, the SDPUC, the NPSC, and the FERC. We are also regulated by many other state and federal agencies. For example, because our operations impact land, waterways and the air, we are subject to a wide range of regulations administered by the federal EPA, the U.S. Fish & Wildlife Service, and parallel state agencies regulating environmental and natural resources in Montana, South Dakota and Nebraska. Another example relates to our provision of natural gas service. The U.S. Department of Transportation through the Pipeline and Hazardous Materials Safety Administration, along with its state partners, regulates natural gas pipeline and natural gas storage field safety. As a publicly-traded company, we are subject to the SEC's requirements regarding financial reporting, disclosures, and laws and regulations protecting investors. We are subject to the Occupational Safety and Health Administration (OSHA), which regulates workplace safety. We are also subject to local zoning laws and regulations.

As detailed below, the rates we charge our utility customers are set through approval by the regulatory commission with jurisdiction in each of our respective service territories. Base rates are the rates that are intended to allow us the opportunity to collect from our customers total revenues (revenue requirements) equal to our cost of providing delivery and rate-based supply services, plus a reasonable rate of return on invested capital. We have both electric and natural gas base rates and cost tracking clauses. We may ask the respective regulatory commission to increase base rates from time to time. Rate increase requests are normally reviewed based on historical data and any resulting approvals may not always keep pace with increasing costs. For more information on current regulatory matters, see Note 5 - Regulatory Matters, to the Consolidated Financial Statements.

The following is a summary of our rate base (amounts we earn a return on) and authorized rates of return in each jurisdiction, estimated as of December 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
		$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. For additional information regarding this acquisition, see Note 4 - Acquisition of Energy West Operations to the Consolidated Financial Statements included herein.
(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.

MPSC Regulation

Nearly all of our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties. We have an obligation to provide service to our customers with an opportunity to earn a regulated rate of return.

Electric Supply Tracking Mechanism - The PCCAM tracks, for recovery through utility rates, the cost of power purchased and fuel used to generate electricity. The PCCAM incorporates sharing of a portion of the business risk or benefit associated

with the energy supply costs with 90 percent of the variance above or below the established base revenues and actual costs collected from or refunded to customers. As part of its December 2025 order, the MPSC has suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC. See Note 5 - Regulatory Matters within the Consolidated Financial Statements for further information. Certain PCCAM rates are adjusted on a quarterly basis for volumes and costs during each July to June 12-month tracking period based on the established base revenues and actual costs collected from or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if electric supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed.

Natural Gas Supply Tracker - Rates for our Montana natural gas supply are set by the MPSC. Certain supply rates are adjusted on a monthly basis for volumes and costs during each July to June 12-month tracking period based on the established base revenues and actual costs collected from or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if natural gas supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed.

Montana Property Tax Tracker **-** We file an annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflects the incremental property taxes since our last base rate filing adjusted for the associated income tax benefit.

SDPUC Regulation

Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our electric and natural gas operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates. Our retail natural gas tariffs include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user. Such transporting customers nominate the amount of natural gas to be delivered daily. On a daily basis, we monitor usage for these customers and balance it against their respective supply agreements.

Adjustment Clauses - An electric adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation, and ad valorem taxes. The adjustment clauses for both electric and gas utilities go into effect upon filing, and are deemed approved within 10 days after the information filing unless the SDPUC Staff requests changes during that period.

Phase In Rate Plan Rider - Effective July 1, 2025, we received approval to begin recovering costs for Aberdeen Generating Station Units 3 & 4 through our Phase in Rate Plan Rider. This tariff allows recovery of capital investments without filing a general electric rate review. SDPUC approval of the plan and associated project cost recovery are required. An update to this plan is required to be filed with the SDPUC by June 1 of each year.

NPSC Regulation

Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation, but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the proposed rate change if the affected communities representing more than 50 percent of the affected ratepayers agree to direct negotiations, or it may proceed to have the NPSC review the filing and make a determination. Our tariffs have been approved by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for biannual, or more often if needed, adjustments based on changes in gas supply and interstate pipeline transportation costs.

FERC Regulation

We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service and electricity sold at wholesale, hydro licensing and operations, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability standards, among other things. Under FERC's open access transmission policy, as owners of transmission facilities, we are required to provide open access to our transmission facilities under filed tariffs at cost-based rates. In addition, we are required to comply with FERC's Standards of Conduct for Transmission Providers.

Our Montana wholesale transmission customers, such as cooperatives, industrial customers, and other customers that have third-party commodity supply providers, receive transmission delivery service under our OATT, which is on file with FERC. The OATT defines the terms, conditions, and rates of our Montana transmission service, including ancillary services. These transmission rates are adjusted annually through formula rates. Our South Dakota transmission operations are in the SPP, and transmission service is provided under the SPP OATT. These transmission rates are adjusted annually through formula rates.

The electricity sold from NW Colstrip 370, which has a 25 percent ownership interest in Colstrip Units 3 & 4, is subject to the FERC's jurisdiction and regulations with respect to rates for electricity sold at wholesale. We have submitted a request to the FERC for approval of cost-based rates and expect this rate approval to be effective in the first quarter of 2026. We have signed a contract to sell the dispatchable capacity and associated energy from NW Colstrip 370 through late 2027. This contract is subject to the approval by the FERC.

Our natural gas transportation pipelines are generally not subject to FERC's jurisdiction, although we are subject to state regulation. We conduct limited interstate transportation in Montana and South Dakota that is subject to FERC jurisdiction, and FERC has allowed the MPSC and SDPUC to set the rates for this interstate service. We have capacity agreements in South Dakota and Nebraska with interstate pipelines that are also subject to FERC jurisdiction.

Our hydroelectric generating facilities are licensed by the FERC and operated in accordance with the terms of those licenses and applicable FERC regulations. As part of the relicensing process, federal law authorizes FERC to issue a new license to the current licensee, to a different licensee, or, alternatively, permits the U.S. government to assume ownership and operation of the facility. If the existing licensee is not granted a new license, it is entitled to compensation equal to its net investment in the facility, not to exceed the fair value of the property taken, plus reasonable severance damages for other property adversely affected by the loss of the license.

Reliability Standards **-** We must comply with the standards and requirements that apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. WECC and the MRO have responsibility for monitoring and enforcing compliance with the FERC-approved mandatory reliability standards within their respective regions. We expect that the reliability standards will continue to evolve and change as a result of modifications, guidance, and clarification following industry implementation and ongoing audits and enforcement.

COMPETITION

We are subject to public policies that promote competition and development of energy markets. Certain of our industrial and large commercial customers have the ability to choose their electric supplier and may generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region. Customers have the opportunity to supply their own power with distributed generation including solar generation, and in Montana, can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. These incentives and federal tax subsidies make distributed generating resources viable potential competitors to our electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Our wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use our transmission systems to serve their load. There is also competition for available transmission capacity to meet our electric supply needs to serve customers.

ENVIRONMENTAL

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and

construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, and protection of natural resources and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are issued, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

In 2024, the EPA released final rules that will potentially impose requirements on fossil fuel assets, however, in 2025, the EPA issued multiple Notices of Proposed Rulemaking that would remove these additional requirements on fossil fuel assets. There is no mandated timeline for final action on these rules. If the MATS Rules are implemented and enforced as currently written, between now and 2028 total compliance costs for the Colstrip plant are estimated to range from $350 million to $665 million, of which we would be responsible for our proportionate share. This estimate has been developed by the Colstrip operator and represents an initial high-level scoping estimate that will require significant refinement to narrow the range of costs, which is currently underway. Without change, implementation of existing environmental regulations have the potential to limit or curtail our operations, including the burning of fossil fuels at our coal-fired and some natural gas power plants. While we strive to comply with all environmental regulations applicable to our operations, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to energy and environmental laws and regulations, or new administrative or judicial interpretations or enforcement decisions regarding them.

For more information on environmental regulations and contingencies and related capital expenditures, see Note 20 - Commitments and Contingencies, to the Consolidated Financial Statements.

CORPORATE INFORMATION AND WEBSITE

We were incorporated in Delaware on May 30, 2023. Our Internet address is https://www.northwesternenergy.com. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Energy Group, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report.

HUMAN CAPITAL RESOURCES

Our ability to achieve the objectives of our business strategy and serve our customers within our service territory depends on employing and continually investing in the development of skilled individuals at all levels of our organization. We aspire to be an employer of choice and a great workplace by offering competitive salaries and benefits and providing a safe working environment where employees can grow personally and in their careers. We value diversity, foster inclusion and encourage a healthful work–life balance that includes taking personal time and giving back to the communities we live and work in. Our success comes when employees feel purpose in the work they do and empowered to take initiative, voice their opinions, and build on their experiences within our company and our communities.

As of December 31, 2025, we had 1,667 employees. Of these, 1,353 employees were in Montana and 314 were in South Dakota or Nebraska. Of our Montana employees, 489, or 36 percent are covered by five unions under eight collective bargaining agreements. All eight of these collective bargaining agreements are set to expire in 2026 and are currently under renegotiation. Of our South Dakota and Nebraska employees, 167, or 53 percent, are covered by a collective bargaining agreement that is set to expire in 2026 and is now being renegotiated. We consider our relations with employees and union leadership to be positive and respectful.

Talent Management

Attraction and retention of skilled employees is key to our ongoing success. We invest resources in maintaining a culture that supports the ongoing development of our workforce. This includes an integrated learning and performance management system which includes annual performance reviews that link goals and competencies together so that managers are able to provide a holistic view to employees in regards to their performance against goals as well as key competencies as they relate to their role in the organization. This process provides opportunities to develop and enhance skills and knowledge, and enables our

employees to grow professionally and perform their duties in a safe and efficient manner. This structured training and development is intended to provide employees a consistent learning experience, and maximizes learning retention and background knowledge. We offer tuition reimbursement to promote continued professional growth for current employees, and a scholarship program for students attending universities, colleges, and technical schools in our service area to assist in developing current and future skills sets needed by our employees. We support annual pre-apprentice scholarships, recruit and hire suitable candidates from the program, serve as industry advisors on the program board and have donated training assets to support the program.

Hiring, promotions, work assignments, or other decisions related to the terms and conditions of employment are made by considering skills, experience, proven track record of performance, and other traits that serve to create a team with varied strengths and backgrounds. Our workforce reflects the available talent in the communities we serve. In compliance with current mandates, our employment data is tested annually by a third party. This testing determined that there is no current need to establish corrective placement goals.

Compensation and Benefits

Our overarching compensation philosophy is structured to be consistent with our peers, and to align the long-term interests of our employees, executives, shareholders, and customers so the pay appropriately reflects performance in achieving financial and non-financial operating objectives. We offer a competitive pay and benefits package, which is benchmarked on an annual basis to external market data. Beyond base pay and incentive compensation, we offer competitive, cost-effective, and well-rounded benefits, which aligns with our desire to be an employer of choice. From considerable employer retirement contributions, to generous paid time off, to health care and well-being programs, our benefits are designed to meet the varied needs of our employees.

We are committed to internal pay equity, and the Human Resources Committee of the Board of Directors monitors the relationship between the pay our executive officers receive and the pay our non-managerial employees receive. During 2025 and 2024, the compensation for our Chief Executive Officer (CEO) was approximately 36 and 34 times, respectively, the compensation of our median employee.

We believe that a significant portion of an executive's pay should be at risk in the form of performance-based incentive awards that are only paid if the individual and company performance targets are met. For 2025, approximately 82 percent of the targeted compensation of our CEO and about 63 percent of the targeted compensation of our other named executive officers is at risk in the form of performance-based incentive awards or time-based awards tied to the value of equity. Our Board of Directors establishes the metrics and targets for these incentive awards, based upon advice from the Board of Directors' independent compensation consultant. In addition, our compensation practices have led to a relatively low CEO to median employee ratio of approximately 36 to 1 for 2025.

We engage nationally recognized outside compensation and benefits consulting firms to independently evaluate the effectiveness of our compensation and benefits programs and to provide benchmarking against our peers within the industry. We provide pay equity between our employees performing equal or substantially similar work. We engage a third party to review our pay equity and share the results with our Board of Directors. Our most recent study was performed in 2024, with no corrective action required.

Health and Safety

As stewards of critical infrastructure, providers of energy service, and members of the communities we serve, our top service value is the safety and well-being of our employees and customers. We integrate safety and health into every aspect of our business, continuously monitoring various areas related to safety practices and policies. Key metrics include the recordable incident rate (the number of work-related injuries per 100 employees over a one-year period) and the lost time incident rate (the number of employees who miss work due to work-related injuries per 100 employees over a one-year period). During the years ended December 31, 2025 and 2024, our recordable incident rates were 1.73 and 1.65, respectively, and lost time incident rates were 0.54 and 0.57, respectively, on a company wide basis.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Executive Officer	Current Title and Prior Employment	Age[1]
Brian B. Bird	President and Chief Executive Officer and Director of NorthWestern Energy Group, Inc., since October 2, 2023, and of NWE Public Service since January 1, 2024, and of NW Corp since January 2023; formerly President and Chief Operating Officer of NW Corp since February 2021 and Chief Financial Officer from December 2003 to February 2021.	63
Crystal D. Lail	Vice President and Chief Financial Officer of NorthWestern Energy Group, Inc., since October 2, 2023, and of NWE Public Service since January 1, 2024, and of NW Corp since February 2021; formerly Vice President and Chief Accounting Officer of NW Corp since April 2020; and Vice President and Controller from October 2015 to April 2020.	47
Shannon M. Heim	Vice President - General Counsel and Federal Government Affairs of NorthWestern Energy Group, Inc., since October 2, 2023, and of NWE Public Service since January 1, 2024, and of NW Corp since January 2023; formerly Director, Regulatory Corporate Counsel of NW Corp since June 2020; and formerly Equity Shareholder at the law firm of Moss & Barnett, P.A. from 2017 to 2020.	53
Bleau J. Lafave	Vice President - Asset Management & Business Development of NW Corp since June 2023 and of NWE Public Service since January 1, 2024; formerly Director of Long-Term Resources of NW Corp since 2003.	55
Bobbi L. Schroeppel	Vice President - Customer Care, Communications and Human Resources of NW Corp since May 2009 and of NWE Public Service since January 1, 2024.	57
Jason C. Merkel	Vice President - Distribution of NW Corp since September 2022 and of NWE Public Service since January 1, 2024; formerly General Manager - Operations and Construction of NW Corp since 2007.	58
Jeanne M. Vold	Vice President - Technology of NW Corp since February 2021 and of NWE Public Service since January 1, 2024; formerly Business Technology Officer of NW Corp since 2012.	59
Michael R. Cashell[2]	Vice President - Transmission of NW Corp since May 2011 and of NWE Public Service since January 1, 2024.	63

(1) As of February 6, 2026.
(2) Michael Cashell has announced that he will retire from the Company in April of 2026.

Officers are elected annually by, and hold office at the pleasure of, the Board of Directors (Board), and do not serve a "term of office" as such.

ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future.

Summary Risk Factors

The following is a summary of some of the risks and uncertainties that could adversely affect our business, financial condition, results of operations or cash flows in the future. You should read this summary together with the more detailed description of each risk factor contained below.

Regulatory, Legislative and Legal Risks

- Our ability to recover prudently incurred costs and earn authorized returns depends on regulatory outcomes;
- Changes in laws, energy policies, or regulatory frameworks may increase costs or limit growth;
- Environmental compliance requirements may require significant investments, which may or may not be recoverable, or early retirements of certain generating facilities;
- Exposure to litigation may delay projects or restrict operations;
- Reliability and safety compliance failures could result in substantial penalties; and
- Mandated QF purchases may increase costs and limit investment flexibility.

Operational Risks

- Utility operations involve hazards that may cause outages, injuries, or environmental harm;
- Increasing fire risk may lead to significant claims or penalties;
- System constraints may limit reliable service or access to lower-cost supply;
- Reliance on market purchases exposes us to price volatility and counterparty risks;
- Weather variability impacts loads, supply, hydrology, and financial performance;
- Fuel supply disruptions may increase costs or reduce generation availability;
- Decreasing customer usage may reduce revenues and increase system costs;
- Cyber and physical security threats may disrupt operations or compromise data;
- Supply-chain delays, inflation, and labor shortages may impair operations; and
- Workforce challenges may affect safety, operations, and project execution.

Liquidity and Financial Risks

- Insurance coverage may be insufficient for certain risks;
- Capital projects and acquisitions carry permitting, cost, and recovery risks;
- Access to capital markets may be constrained by interest rates or volatility;
- Energy transition policies and technologies present financial and operational risks;
- Credit rating downgrades would increase borrowing costs and collateral needs;
- QF minimum energy obligations may expose us to higher replacement power costs;
- Changes in tax laws may affect earnings and cash flows;
- Counterparty defaults may impact liquidity;
- Pension and benefit plan performance may increase costs; and
- We rely on subsidiary dividends subject to regulatory constraints.

Risks Related to the Merger

- The fixed exchange ratio creates variability in merger consideration value;
- Required approvals may delay, condition, or prevent merger completion;
- Deal protections and termination fees may discourage alternatives;
- Merger uncertainty may impact stock price, ratings, and operations; and
- Merger-related litigation may cause delays or additional costs.

Risks Relating to the Combined Company Following Completion of the Merger

- Integration challenges may delay or reduce anticipated synergies;
- NorthWestern shareholders will have reduced ownership and voting influence;
- Significant indebtedness may increase refinancing and interest-rate risks;

- Goodwill created in the merger may be subject to impairment;
- Tax attribute limitations may reduce expected NOL benefits;
- Future dividends are not assured; and
- Issuance of new Black Hills Common Stock could negatively impact the Black Hills Common Stock price

Regulatory, Legislative and Legal Risks

Our profitability depends on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We are subject to potential unfavorable litigation, and state and federal regulatory outcomes. To the extent our incurred costs are deemed imprudent by the applicable regulatory commissions or certain regulatory mechanisms are not available, we may not recover some of our costs or collect them in a timely manner, which could adversely impact our results of operations and liquidity.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and rates that we can charge customers. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital and rates are generally set through a process called a rate review (or rate case) in which the utility commission analyzes our costs incurred during a historical test year and decides whether they may be included in our base rates. In addition to formal general rate reviews, we also have cost tracking mechanisms that are intended to allow us to recover prudently incurred costs. There can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in rates that allow us the opportunity to earn our authorized return or provide for timely and full recovery of such costs. In 2025, the MPSC disallowed $30.9 million of capital costs that they deemed were not prudently incurred related to the construction of YCGS. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. Differing schedules and regulatory practices between our state commissions and FERC expose us to the risk that we may not fully recover our costs due to timing of filings, specific calculations and issues such as cost allocation methodologies. We are required to have FERC approved cost based rates or FERC approved contract rates in order to sell electricity in the wholesale market. Absent these rates, we may be subject to refund of some or all of the revenue collected. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Adverse regulatory rulings could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

We are subject to changing federal and state laws and regulations. Congress and state legislatures may enact legislation that adversely affects our operations and financial results.

We are subject to regulations under a wide variety of U.S. federal and state regulations and policies. Regulation affects almost every aspect of our business. Changes to federal and state laws and regulations are continuous and ongoing and the federal administration, the U.S. Congress, state legislatures and state administrations may enact and implement new laws and regulations that could adversely and materially affect us. For example, legislation and regulations may be enacted that require or facilitate alternative generation or storage which, in turn, could result in customers using less of our energy or facilities which could reduce our revenues and our growth opportunities. We cannot predict future changes in laws and regulations, how they will be implemented and interpreted, or the ultimate effect that this changing environment will have on us. There can be no assurance that laws, regulations and policies will not be changed in ways that have a material adverse effect on our operations, financial condition, results of operations, and cash flows.

We are subject to extensive and changing energy, and environmental laws and regulations with which compliance may be difficult and costly.

Our operations are subject to laws and regulations imposed by federal, state and local government authorities regarding energy policy, permitting/siting for energy projects, the environment, air and water quality, GHG emissions, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations.

In response to recent regulatory and judicial decisions and international accords, GHG emissions, most significantly CO_2, could be restricted in the future as a result of federal or state legal requirements or litigation relating to GHG emissions. In 2024, the EPA released final rules that will potentially impose requirements on fossil fuel assets, however, in 2025, the EPA issued multiple Notices of Proposed Rulemaking that would remove these additional requirements on fossil fuel assets. There is no mandated timeline for final action on these rules. If these promulgated GHG and MATS Rules are implemented and enforced as currently written, they may affect our ability to reliably serve our customers and we could be subject to significant additional compliance costs that would affect our future financial position, results of operations, and cash flows if such costs are

not recovered through regulated rates. Such changes also could affect the manner in which we conduct our business and could require us to make substantial additional capital expenditures or abandon certain projects.

To the extent that costs exceed our estimated environmental liabilities, or we are not successful in recovering remediation costs or costs to comply with the proposed or any future changes in rules or regulations, our results of operations and financial position could be adversely affected. Certain environmental laws and regulations also provide for substantial civil and criminal fines for noncompliance which, if imposed, could result in material costs or liabilities.

In addition, there is a risk of environmental damage claims from private parties or government entities. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws.

We are also at risk of unfavorable litigation outcomes related to zoning and environmental permits. In 2023, due to lawsuits filed by the Montana Environmental Information Center and Sierra Club alleging that the environmental analysis conducted by the MDEQ prior to the issuance of the YCGS air quality construction permit was inadequate, the Montana District Court issued an order vacating our YCGS air quality permit pending the MDEQ addressing the identified deficiencies. While we eventually were successful in staying this order, and the air quality permit was subsequently reinstated, due to this litigation we paused construction for approximately three months, causing us to incur substantial additional costs. Adverse litigation outcomes, such as this, could cause us to delay or terminate projects, increase costs and impact our ability to service our customers.

Early closure of our owned and jointly owned electric generating facilities due to environmental risks, litigation or public policy changes could have a material adverse impact on our results of operations and liquidity.

While a majority of our Company-wide electric supply portfolio is carbon-free, it does include fossil-fuel resources. Environmental advocacy groups, certain investors and other third parties oppose the operation of fossil-fuel generation, expressing concerns about the environmental-related impacts from fossil fuels. This opposition may increase in scope and frequency depending on a number of variables, including the course of Federal and State laws and environmental regulations and the financial resources devoted to opposition efforts. These risks include litigation against us due to GHG or other emissions or coal combustion residuals disposal and storage; activist shareholder proposals; and increased activism before our regulators. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities. In addition, defense costs associated with litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

In particular, as described more fully below in Note 20 - Commitments and Contingencies to the Consolidated Financial Statements included herein, we are a co-owner of the coal-fired Colstrip Units 3 & 4 generating facility. The remaining depreciable life of our investments in Colstrip Units 3 & 4 is through 2042.

Increased risks of regulatory penalties could negatively impact our business.

We must comply with established reliability standards and requirements including Critical Infrastructure Protection Reliability Standards, which apply to NERC functions. NERC reliability standards protect the nations' bulk power system against potential disruptions from cyber and physical security breaches. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Penalties for the most severe violations can reach nearly $1.2 million per violation, per day. If a serious reliability incident or other incidence of noncompliance did occur, it could have a material adverse effect on our operating and financial results.

Additionally, the Pipeline and Hazardous Materials Safety Administration, Occupational Safety and Health Administration and other federal or state agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Federally mandated purchases of power from QFs, and integration of power generated from those projects in our system, may increase costs to our customers and decrease system reliability, limit our ability to make generation investments and adversely affect our business.

We are generally obligated under federal law to purchase power from certain QF projects, regardless of current load demand, availability of lower cost generation resources, transmission availability or market prices. Although some of these resources include a battery component, they are primarily intermittent generation whose prices may be in excess of market prices during times of lower customer demand, and may not be able to generate electricity during peak times. These resources typically do not meet the requirements set forth in our supply plans for resource procurement. These requirements to purchase supply that is inconsistent with customer need may have multiple impacts, including increasing the likelihood and frequency that we will be required to reduce output from owned generation resources, negatively impacting our ability to make our own generation investments and increasing the likelihood that we will need to upgrade or build additional transmission facilities to serve QF projects. Any of these results would increase costs to customers and impact our investment plan. Further, balancing load and power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs, those increased costs may negatively affect our liquidity, results of operations and financial condition.

In addition, requirements to procure power from these sources could impact our ability to make generation investments depending upon the number and size of QF contracts we ultimately enter into. The cost to procure power from these QFs may not be a cost effective resource for customers, or the type of generation resource needed, resulting in increased supply costs that are inconsistent with resource plans developed based on a lowest cost and least risk basis while placing upward pressure on overall customer bills. This may impact our investment plans and financial condition. Finally, the requirement to procure power from these QF sources may impact our transmission system and require additional transmission facilities to be developed in order to integrate these resources, which also can impact overall customer bills.

Operational Risks

Our electric and natural gas operations involve numerous activities that may result in accidents, fires, system outages and other operating risks and costs that are unique to our industry.

Inherent in our electric transmission and distribution and natural gas transmission and distribution operations are a variety of hazards and operating risks, such as breakdown or failure of equipment or processes, interruptions in fuel supply, supply chain interruptions, labor disputes, operator error, and catastrophic events such as fires, electric contacts, leaks, explosions, floods and intentional acts of destruction. For our natural gas lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of potential damages resulting from these risks could be significant. These risks could cause a loss of human life, facility shutdown or significant damage to property, service interruption, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others.

Fire risk is significant in the western United States, including in our service territory. Various factors in recent years have contributed to increasing fire risk including dead and dying trees, warmer air temperatures, drought, wind, forest management practices, and land management practices. These factors increase the risk of a fire in both forests and grasslands. In forested areas, this issue has been heightened by mountain pine beetle and other infestations weakening and killing trees in our service territory. Residential and commercial development into the wildland-urban interface has also led to an increasing trend in the degree of destruction from wildfires.

Fires alleged to have been caused by our equipment potentially expose us to significant penalties and/or damage awards based on claims of strict liability, negligence, gross negligence, inverse condemnation, nuisance, trespass and others. Our equipment has been alleged to be involved in igniting wildfires although none have had a material adverse effect on our financial condition or results of operations.

For our electric generating facilities, operational risks include facility shutdowns due to breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation, litigation or regulation. The loss of a major electric generating facility would require us to find other sources of supply or ancillary services, if available, and expose us to higher purchased power costs and potential litigation which may not be recovered from customers.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Additionally, during peak-load periods our electric and natural gas systems in Montana are constrained. These constraints limit our ability to transmit electric energy within Montana and access electric energy from outside the service area. Our electric transmission facilities are also interconnected with those of third parties, and thus operation of these facilities could be adversely affected by unexpected or uncontrollable events. Our natural gas system is also constrained, which limits our on-system deliverability and the ability to transport gas. We are similarly exposed to risk of interconnection with third-party pipelines and are dependent upon their operation to serve customers. These transmission constraints and events could result in failure to provide reliable service to customers due to the inability to deliver energy supply resources, or could result in significant cost increases due to the inability to access lower cost sources of energy supply.

Our electric and natural gas portfolios rely significantly on market purchases. This exposure adversely affects our ability to manage our operational requirements to reliably serve our customers, while exposing us to market volatility, which ultimately could adversely affect our results of operations and liquidity.

We are obligated to supply power to retail customers and certain wholesale customers and procure natural gas to supply fuel for our natural gas fired generation. Our need to acquire flexible energy supply and capacity in the market to meet our electric and natural gas load serving obligations exposes us to certain risks including the ability to reliably serve customers and significant uncertainty in the cost of supply, which may not be recoverable. We rely upon a combination of base-load supply from our owned and long-term contracted generation and market purchases to serve customers. During peak periods, power demand could exceed, and has exceeded, the available capacity of our owned and long-term contracted generation capacity, requiring us to purchase capacity and energy from the market. In the past, we have relied upon both in-state and out-of-state power purchase agreements for grid reliability and to physically serve customers. A significant number of base-load generation facilities, which may also serve to meet peak requirements, in the state and region have been retired or are scheduled to be retired in the next five to ten years.

This includes Colstrip Units 1 and 2, representing 614 MWs of generation on a capacity basis, which ceased operations in January 2020. A decrease in the state and region's electric capacity, whether for operational reasons or litigation outcomes, may impair the reliability of the grid, particularly during peak demand periods. There can be no assurance that there will be available counterparties to contract with to serve our customers' needs, or that these counterparties will fulfill their obligations to us. There is also no assurance that the transmission capacity required to import market purchases will be available on transmission systems owned by us or by third parties. In addition, the suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. These conditions could result in an inability to physically deliver electricity to our customers. Losing electric service during extreme conditions carries significant consequences, as without our services our customers may be subjected to dire circumstances.

Commodity pricing is an inherent risk component of our business operations and our financial results. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our costs are recoverable, as discussed above. The prevailing market prices for electricity may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows due to our need for market purchases and the sharing component of the Montana PCCAM. During recent periods, we have had a significant under-collection of these costs impacting our results of operations and cash flows. As described more fully below in Note 5 - Regulatory Matters to the Consolidated Financial Statements included herein, while the MPSC has suspended the sharing component of the Montana PCCAM beginning on February 1, 2026, pending further review, there can be no assurances that a final order will be issued eliminating this sharing component.

In addition, our natural gas system serves both retail customers and the needs of natural gas fired electric generation. The natural gas system has capacity constraints that expose us to risks to be able to deliver natural gas during periods of peak demand.

Fluctuations in actual weather conditions, generation availability, transmission constraints, and generation reserve margins may all have an impact on market prices for energy and capacity and the electricity consumption of our customers on a given day. Extreme weather conditions may force us to purchase electricity in the short-term market on days when weather is unexpectedly severe, and the pricing for market energy may be significantly higher on such days than the cost of electricity in our existing generation and contracts. Unusually mild weather conditions could leave us with excess power which may be sold in the market at a loss if the market price is lower than the cost of electricity in our existing contracts.

Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events, could adversely affect our ability to manage our operational requirements to serve our customers, and ultimately adversely affect our results of operations and liquidity.

Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters or cool summers could adversely affect our results of operations and financial position. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas. Our sensitivity to weather volatility is significant due to the absence of regulatory mechanisms, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs.

Severe weather impacts, including but not limited to, blizzards, thunderstorms, high winds, microbursts, floods, fires, tornadoes and snow or ice storms can disrupt energy generation, transmission and distribution. We derive a significant portion of our energy supply from hydroelectric facilities, and the availability of water can significantly affect operations. Higher temperatures may decrease the Montana snowpack and impact the timing of run-off and may require us to purchase replacement power. Dry conditions, which exist in the West and in our service territory, also increase the threat of fires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, fires that are alleged to have been caused by our system could expose us to substantial property damage and other claims. Any damage caused as a result of fires could negatively impact our financial condition, results of operations or cash flows.

Extreme weather conditions, especially those of prolonged duration, create high energy demand on our own and/or other systems and increase the risk we may be unable to reliably serve customers, causing brownouts and/or blackouts of our electric systems, and loss of gas supply. Risk of losing electricity or gas supply during extreme weather carries significant consequences as without our services our customers may be subjected to dire circumstances. Additionally, extreme weather conditions may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather

events increases, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks.

Our results of operations may be impacted by disruptions to fuel supply or the electric grid that are beyond our control.

We are exposed to risks related to performance of contractual obligations by our suppliers, which includes parties transporting natural gas. We are dependent on coal and natural gas for a significant portion of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short- and long-term contracts. We have certain supply and transportation contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply and deliver coal and natural gas to us. For instance, there currently is litigation pending relating to adequacy of certain permits for the Rosebud Mine in Montana, which supplies coal to Colstrip and contains significant quantities of coal. In order to operate the Colstrip facility through its currently identified depreciable life of 2042, it will be necessary to identify and contract for coal supply subsequent to expiration of our current contract in 2033. Moreover, the suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply or transport coal and natural gas to us under certain circumstances, such as in the event of a natural disaster. Deliveries may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather, availability of equipment and labor shortages. Failure or delay by our suppliers of coal and natural gas deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers.

Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event such as a severe storm, generator or transmission facility outage on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial position, results of operations and cash flows.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions or response to price increases. We are also impacted by market conditions outside of our service territories related to demand for transmission capacity and wholesale electric pricing.

Our revenues, results of operations and financial condition are impacted by customer growth and usage, which can be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in their disposable income, and the use of distributed generation resources or other emerging technologies for electricity. Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production. Customer-owned generation itself reduces the amount of electricity purchased from utilities and may have the effect of inappropriately increasing rates generally and increasing rates for customers who do not own generation, unless retail rates are designed to collect distribution grid costs across all customers in a manner that reflects the benefit from their use. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Decreasing use per customer (driven, for example, by appliance and lighting efficiency) and the availability of cost-effective distributed generation, put downward pressure on load growth. There can be no assurance that load growth from large-load customers, such as data centers, will be realized. Reductions in usage, attributable to various factors could materially affect our results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions. The levels of wholesale sales depend on the wholesale market price, market participants, transmission availability, the availability of generation, and the ongoing development of the Western EIM, among other factors. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows.

Cyber and physical attacks, threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may affect our operations in unpredictable ways and could adversely affect our liquidity and results of operations. Failure to maintain the security of personally identifiable information could adversely affect us.

Business Operations - We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber attacks, physical security breaches and other disruptive activities of individuals or groups, and theft of our critical infrastructure information. Our generation, transmission and distribution facilities are deemed critical infrastructure and provide the framework for our service infrastructure. Cyber crime, which includes the use of malware, phishing attempts, computer viruses, and other means for disruption or unauthorized access has increased in frequency, scope, and potential impact in recent years. The advancement of artificial intelligence and large language models has given rise to additional vulnerabilities and potential entry points for cyber crime. Our assets and the information technology systems on which they depend are direct targets of, or are indirectly affected by, cyber attacks and other disruptive activities, including those that impact third party facilities that are interconnected to us. Any significant interruption of these assets or systems could prevent us from fulfilling our critical business functions including delivering energy to our customers, and sensitive, confidential and other data could be compromised.

Security threats continue to evolve and transform. The risk of cyber-based attacks is heightened due to recent geopolitical events as well as employees working and accessing our technology infrastructure remotely. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, to confidential data, or to disrupt operations. With the continuing rise in ransomware and other cyber-based threats we continuously analyze our technology platforms and monitoring for signs of potential intrusions. There is also a risk of exposure of confidential or proprietary data through the inadvertent use of open artificial intelligence tools. We periodically engage with our vendors, suppliers and contractors to establish that they are taking appropriate measures. None of these attempts has individually or in the aggregate resulted in a security incident with a material impact on our financial condition or results of operations. However, despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact.

These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure assets, and could adversely affect our operations by contributing to the disruption of supplies and markets for electricity, natural gas, oil and other fuels. These events could also impair our ability to raise capital by contributing to financial instability and reduced economic activity.

Personally Identifiable Information - Our information systems and those of our third-party vendors contain confidential information, including information about customers and employees. Customers, shareholders, and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject us to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm our reputation.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We may have difficulty cost-effectively completing certain operations activities and construction projects due to inflationary pressures or if our third-party business partners are unable to deliver ordered supplies or complete contracted services timely, including workforce shortages or macro supply chain disruptions.

We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, potential tariffs on imported products, scarcities/shortages, longer fulfillment times for orders from our suppliers, workforce availability, and wage increases.

Should these economic conditions and issues continue, we could have difficulty completing the operational activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which ultimately could result in higher customer utility rates, longer outages, and could have a material adverse impact on our business, financial condition and operations.

Failure to attract and retain an appropriately qualified workforce could affect our operations.

We require skilled labor to perform specialized utility functions. Turnover of key employees without appropriate replacements may lead to operating challenges and increased costs. Some of the challenges include lack of resources, loss of knowledge, and time required for replacement employees to develop necessary skills. Wage inflation nationally and increased competitive labor markets may make it difficult to attract employees. Failure to identify qualified replacement employees could result in decreased productivity and increased safety costs. If we are unable to attract and retain an appropriately qualified workforce, our operations could be negatively affected. We are also subject to multiple collective bargaining agreements. Future negotiation of these collective bargaining agreements could lead to work stoppages or other disruptions to our operations, which could adversely affect our financial condition and results of operations.

Liquidity and Financial Risks

We may be unable to obtain insurance coverage, and the coverage we currently have may not apply or may be insufficient to cover a significant loss.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting the insurance industry and the financial condition of insurers. Additionally, insurance providers could deny coverage or decline to extend coverage under the same or similar terms that are presently available to us. A loss for which we are not adequately insured could materially affect our financial results. The coverage we currently have in place may not apply to a particular loss, or it may not be sufficient to cover all liabilities to which we may be subject, including liability and losses associated with wildfires, natural gas and storage field explosions, cyber-security breaches, environmental hazards and natural disasters.

Our plans for future expansion through the acquisition of assets, capital improvements to existing assets, generation investments, and transmission grid expansion involve substantial risks.

Our business strategy includes significant investment in capital improvements and additions to modernize existing infrastructure, generation investments and transmission capacity expansion. The completion of generation and natural gas investments and transmission projects are subject to many construction and development risks, including, but not limited to, risks related to permitting, financing, regulatory recovery, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. In addition, these capital projects may require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support such projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital.

Acquisitions include a number of risks, including but not limited to, regulatory approval, regulatory conditions, additional costs, the assumption of material liabilities, the diversion of our attention from daily operations to the integration of the acquisition, difficulties in assimilation and retention of employees, and securing adequate capital to support the transaction. The regulatory process in which rates are determined may not result in rates that produce full recovery of our investments, or a reasonable rate of return. Uncertainties also exist in assessing the value, risks, profitability, and liabilities associated with certain businesses or assets and there is a possibility that anticipated operating and financial synergies expected to result from an acquisition do not develop. The failure to successfully integrate future acquisitions that we may choose to undertake could have an adverse effect on our financial condition and results of operations.

Access to capital markets is critical to our operations and our capital structure. Increasing interest rates could have a material negative impact on our financial condition.

We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, U.S. and regional economies impacts our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms. We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time-to-time. For example, we have $105 million of secured long-term debt and $150 million of short-term borrowings maturing in 2026. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

We are subject to financial risks associated with the transition to a lower carbon economy.

The risks related to our transition to a lower-carbon economy, creates financial risk. Transition risks represent those risks related to the social and economic changes needed to shift toward a lower carbon future. These risks are often interconnected, representing policy and regulatory changes, technology and market risks, and risks to our reputation and financial performance.

Potential regulation associated with climate change legislation could pose financial risks to us. Although the U.S. is no longer a party to the United Nations' "Paris Agreement" on climate change, other potential legislation and regulation discussed above, could result in enforceable GHG emission reduction requirements that could lead to increased compliance costs for us.

As we expand our energy generation asset mix, the ability to integrate renewable technologies into our operations and maintain reliability and affordability is a risk. The intermittency of renewables remains a critical challenge particularly as cost-

efficient energy storage is still in development. Other technology risks include the need for significant upfront financial investments, lengthy development timelines, and the uncertainty of integration and scalability across our entire service territory.

There are also increasing risks for energy companies from shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change who may elect in the future to shift some or all of their investments into entities that emit lower levels of GHG emissions or into non-energy related sectors. Institutional investors and lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable investing and lending practices and some of them may elect not to provide funding for fossil fuel energy companies. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We may be subject to financial risks from private party litigation relating to GHG emissions. Defense costs associated with such litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected.

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. We continue to maintain our investment grade credit ratings. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations.

Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to make up the difference.

As part of a stipulation in 2002 with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH through June 2029. This obligation is reflected in the electric QF liability, which reflects the unrecoverable costs associated with these specific QF contracts per the stipulation. The annual minimum energy requirement is achievable under normal operations of these facilities, including normal periods of planned and forced outages. However, to the extent the supplied power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to purchase the difference from other sources. The anticipated source for any shortfall is the wholesale market, which would subject us to commodity price risk if the cost of replacement power is higher than contracted rates. To the extent the cost of replacement power is higher than contracted rates, our results of operations, cash flows and financial position could be adversely affected.

Changes in tax law may significantly impact our business.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we operate. Similar to the Tax Cuts and Jobs Act, sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which a change in corporate tax rate will affect our utility customers and the time period over which that change will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates and therefore may impact our results of operations, cash flows and financial position.

We are subject to counterparty credit risk.

We enter into transactions to buy and sell power, natural gas, and transmission service. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. Certain of these contracts may result in the receipt of, or posting of, collateral with counterparties. Fluctuations in commodity prices that lead to the posting of collateral with counterparties negatively impact liquidity, and downgrades in our credit ratings may lead to additional collateral posting requirements.

We are a participant in the energy markets, including the EIM, and engage in direct and indirect power purchase and sale transactions in connection with that participation. The EIM has collateral posting requirements based on established credit criteria, but there is no assurance the collateral will be sufficient to cover obligations that counterparties may owe each other in the EIM and any such credit losses could be socialized to all EIM participants, including us. A significant failure of a participant in the EIM to make payments when due on its obligations could have a ripple effect on various of our counterparties in the power and gas markets if those counterparties experience ancillary liquidity issues, and could generally result in a decline in the ability of our counterparties to perform on their obligations.

We also extend credit to our customers in the ordinary course of business in each of our operating segments. Our customers' ability to pay depends on a variety of factors including macroeconomic conditions, local economic conditions, including unemployment rates, and industry conditions in which our commercial and industrial customers operate. Increased customer delinquencies and bad debts could adversely impact our operating results and liquidity.

Poor investment performance of plan assets of our defined benefit pension and postretirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity.

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors. Assumptions related to future costs, return on investments and interest rates have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance and changes in governmental regulations. Without sustained growth in the plan assets over time and depending upon interest rate changes as well as other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

We have a holding company structure and rely on cash from our subsidiaries to pay dividends.

As a holding company, our primary assets are our investments in our subsidiaries, NW Corp and NWE Public Service. Substantially all operations are conducted by NW Corp (and its subsidiaries) and NWE Public Service. We depend on earnings, cash flows and dividends from our subsidiaries to pay dividends on our common stock. Regulatory, contractual and legal limitations, as well as subsidiary capital requirements, affect the ability of a subsidiary to pay dividends up to the parent entity and thereby could restrict or influence our ability or decision to pay dividends on our common stock, which could adversely affect our stock price.

Risks Related to the Merger

Because the exchange ratio is fixed and because the market prices of NorthWestern Common Stock and Black Hills Common Stock will fluctuate, NorthWestern shareholders cannot be certain of the market value of the Merger consideration they will receive in the Merger or the difference between the market value of the Merger consideration they will receive in the Merger and the market value of NorthWestern Common Stock immediately prior to the Merger.

The exchange ratio in the Merger is fixed and will not be adjusted in the event of any change in the stock prices of NorthWestern or Black Hills prior to the Merger. There may be a significant amount of time between the dates when the shareholders of NorthWestern or Black Hills vote on the Merger Agreement at the special meeting of each company and the date when the Merger is completed. The absolute and relative prices of shares of NorthWestern Common Stock and Black Hills Common Stock may vary significantly between the date the Merger Agreement, the date hereof, the date of the meetings and the date of the completion of the Merger. These variations may be caused by, among other things, changes in the businesses, operations, results or prospects of NorthWestern or Black Hills, market expectations of the likelihood that the Merger will be completed and the timing of completion, the prospects of post-merger operations, general market and economic conditions and other factors. In addition, it is impossible to predict accurately the market price of the Black Hills Common Stock to be received by NorthWestern shareholders after the completion of the Merger. Accordingly, the prices of NorthWestern Common Stock and Black Hills Common Stock on the date hereof and on the date of the meetings may not be indicative of their prices immediately prior to completion of the Merger and the price of the combined company common stock after the Merger is completed.

The ability of NorthWestern and Black Hills to complete the Merger is subject to various closing conditions, including the receipt of approval of NorthWestern and Black Hills stockholders and the receipt of consents and approvals from various governmental authorities, which may impose conditions that could adversely affect NorthWestern or Black Hills or cause the Merger to be abandoned. Failure to complete the Merger, or significant delays in completing the Merger, could negatively affect the trading price of NorthWestern common stock or other securities and the future business and financial results of NorthWestern.

To complete the Merger, NorthWestern and Black Hills stockholders must vote to approve a number of proposals related to the Merger and the Merger Agreement. Further, the Merger is subject to the satisfaction or waiver of certain closing conditions, including, (1) subject to certain conditions, the receipt of certain regulatory approvals, including expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act (the HSR Act), and approval from the FERC and certain state regulatory commissions, in each case on such terms and conditions that would not result in a material adverse effect on the combined company; (2) the absence of any court order or regulatory injunction prohibiting completion of the Merger; (3) the authorization for listing of shares of Black Hills Common Stock to be issued in connection with the Merger on the New York Stock Exchange (NYSE) or other mutually-agreed stock exchange; (4) subject to specified materiality standards, the accuracy of the representations and warranties of each party; (5) compliance by each party in all material respects with its covenants under the Merger Agreement; (6) the absence of a material adverse effect on each party; and (7) receipt by each party of an opinion relating to the anticipated tax-free treatment of the Merger. If the foregoing conditions are not satisfied or waived, one or both of NorthWestern or Black Hills would not be required to complete the Merger.

NorthWestern and Black Hills have not yet obtained stockholder approval or all of the regulatory consents and approvals required to complete the Merger. Governmental or regulatory agencies could seek to block or challenge the Merger or could impose restrictions they deem necessary or desirable in the public interest as a condition to approving the Merger. NorthWestern and Black Hills will be unable to complete the Merger until the waiting period under the HSR Act has expired or been terminated and the required governmental approvals have been received. Regulatory authorities may impose certain requirements or obligations as conditions for their approval. The Merger Agreement may require NorthWestern and/or Black Hills to accept conditions from these regulators that could adversely impact the combined company. If the required governmental approvals are not received, or they are not received on terms that satisfy the conditions set forth in the Merger Agreement, then neither NorthWestern nor Black Hills will be obligated to complete the Merger.

There can be no assurance that a challenge to the Merger on antitrust grounds will not be made or, if such a challenge is made, of the result of such challenge. Additionally, even after the statutory waiting period under the antitrust laws and even after completion of the Merger, governmental authorities could seek to block or challenge the Merger as they deem necessary or desirable in the public interest. In addition, in some jurisdictions, a private party could initiate an action under the antitrust laws challenging or seeking to enjoin the Merger, before or after it is completed. NorthWestern or Black Hills may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

The special meetings at which the NorthWestern stockholders and the Black Hills stockholders will vote on the transactions contemplated by the Merger Agreement may take place before all regulatory approvals have been obtained and, in cases where they have not been obtained, before the terms of any conditions to obtain such regulatory approvals that may be imposed are known. As a result, if stockholder approval of the transactions contemplated by the Merger Agreement is obtained at such meetings, NorthWestern may make decisions after the meetings to waive a condition or approve certain actions required to obtain the necessary approvals without seeking further stockholder approval. Such actions could have an adverse effect on the combined company.

If NorthWestern and Black Hills are unable to complete the Merger, or there is a significant delay in completing the Merger, NorthWestern would be subject to a number of risks, including the following:

- NorthWestern would not realize the anticipated benefits of the Merger, including, among other things, increased operating efficiencies and future cost savings;
- the attention of management of NorthWestern may have been diverted to the Merger rather than to its own operations and the pursuit of other opportunities that could have been beneficial to NorthWestern;
- the potential loss of key personnel during the pendency of the Merger as employees may experience uncertainty about their future roles with the combined company;
- NorthWestern will have been subject to certain restrictions on the conduct of its business, which may prevent NorthWestern from making certain acquisitions or dispositions or pursuing certain business opportunities while the Merger is pending;
- the trading price of NorthWestern Common Stock or other securities may decline to the extent that the current market prices reflect a market assumption that the Merger will be completed; and
- the parties may be liable for damages to one another, or have to pay a termination fee, under the Merger Agreement.

NorthWestern can provide no assurance that the various closing conditions will be satisfied and that the required governmental approvals and other approvals will be obtained, or that any required conditions will not materially adversely affect the combined company following the Merger. In addition, NorthWestern can provide no assurance that these conditions will not result in the abandonment or delay of the Merger. The occurrence of any of these events individually or in combination could have a material adverse effect on NorthWestern's results of operations and the trading price of NorthWestern's Common Stock or other securities.

The Merger Agreement contains provisions that limit NorthWestern's ability to pursue alternatives to the Merger, could discourage a potential acquirer of NorthWestern from making a favorable alternative transaction proposal and, in certain circumstances, could require NorthWestern to pay a termination fee to Black Hills.

Under the Merger Agreement, NorthWestern and Black Hills have agreed, subject to certain exceptions with respect to unsolicited proposals, not to directly or indirectly solicit competing acquisition proposals or to enter into discussions concerning, or provide confidential information in connection with, any unsolicited alternative acquisition proposals. Additionally, the NorthWestern board of directors and the Black Hills board of directors are each required to recommend the approval of the applicable transaction-related proposals to its respective stockholders, subject to certain exceptions. Prior to the approval of the transaction-related proposals by their respective stockholders, the NorthWestern board of directors or the Black Hills board of directors may change its recommendation in response to an unsolicited proposal for an alternative transaction, if such board of directors determines in good faith after consultation with its outside legal counsel and financial advisor that the proposal constitutes or would reasonably be expected to lead to a “Superior Black Hills Proposal” or “Superior NorthWestern Proposal”, as applicable (as such terms are defined in the Merger Agreement), and that failure to take such action would be inconsistent with their fiduciary duties under applicable law to the applicable company and its stockholders under applicable law, subject to complying with certain procedures set forth in the Merger Agreement. Prior to the approval of the transaction-related proposals by their respective stockholders, the NorthWestern board of directors and the Black Hills board of directors may also change its recommendation upon the occurrence of a “Black Hills Intervening Event” or “NorthWestern Intervening Event”, as applicable (as such terms are defined in the Merger Agreement), and such board of directors determines in good faith after consultation with its outside legal counsel and financial advisor that failing to change its recommendation would be inconsistent with its fiduciary duties under applicable law, subject to complying with certain procedures set forth in the Merger Agreement. The Merger Agreement is subject to a “force-the-vote” provision, which means neither NorthWestern nor Black Hills would have an independent right to terminate the Merger Agreement to accept a superior proposal. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of NorthWestern from considering or proposing that acquisition, even if such third party were prepared to pay consideration with a higher market value than the market value proposed to be received or realized in the Merger, or might result in a potential acquirer proposing to pay a lower price than it would otherwise have proposed to pay. As a result of these restrictions, NorthWestern may not be able to enter into

an agreement with respect to a more favorable alternative transaction, or may be able to do so only by incurring potentially significant liability to Black Hills.

The Merger Agreement contains certain customary termination rights for each of NorthWestern and Black Hills; provided, that, either party would be required to pay to the other a termination fee equal to $100 million upon termination of the Merger Agreement in certain circumstances involving (i) a change in recommendation by such party's board of directors (including, in certain circumstances, the failure of such party to publicly reaffirm its recommendation upon request) or (ii) a party entering into a definitive agreement in respect of a competing transaction within twelve months of termination of the Merger Agreement in certain circumstances involving a potential competing acquisition proposal.

NorthWestern is subject to risk of the Merger having adverse impact on its credit rating while the Merger is pending.

NorthWestern cannot be assured that its credit ratings will not be lowered as a result of the Merger or for any other reason, including the failure to consummate the Merger. Any reduction in NorthWestern's credit ratings, or the criteria used by rating agencies to determine such ratings, could adversely affect its ability to complete the Merger, its access to capital, its cost of capital and its other operating costs, and its ability to refinance or repay NorthWestern's existing debt and complete new financings, which could have a material adverse effect on NorthWestern's business, financial condition, results of operations or the trading price of its common stock or other securities.

The market prices of NorthWestern Common Stock and other securities may be subject to fluctuation while the Merger is pending.

The market price of NorthWestern Common Stock and other securities may fluctuate significantly while the Merger is pending, and any adverse developments related to the Merger or otherwise could result in holders of NorthWestern Common Stock or other securities losing some or all of the value of their investment. In addition, if the stock market experiences significant price and volume fluctuations, such fluctuations could be exacerbated by the pendency of the Merger, which could adversely affect the market for, or liquidity of, NorthWestern Common Stock or other securities, regardless of NorthWestern's actual operating performance.

Because the Merger Agreement contemplates that Black Hills will issue shares of Black Hills Common Stock to NorthWestern's stockholders based upon a fixed exchange ratio (subject to certain adjustments for reclassifications, stock splits, and stock dividends), developments with respect to Black Hills and its shares of common stock may affect NorthWestern Common Stock irrespective of their relevance to standalone NorthWestern and even though NorthWestern may have no control over, or knowledge of, such developments. As a result, the market price of NorthWestern Common Stock during the pendency of the Merger may not accurately reflect the value of NorthWestern absent the Merger.

NorthWestern is subject to contractual restrictions in the Merger Agreement that may hinder its operations while the Merger is pending. The corollary restrictions applicable to Black Hills may not prevent Black Hills from taking actions that are adverse to NorthWestern or its stockholders.

The Merger Agreement includes certain customary restrictions with respect to the operation of NorthWestern's and Black Hills' respective businesses between the date of the Merger Agreement and the consummation of the Merger. These restrictions may prevent NorthWestern from pursuing otherwise attractive business opportunities and making other changes to its business prior to completion of the Merger or termination of the Merger Agreement.

Despite these mutual restrictions, NorthWestern and Black Hills will continue to operate their businesses independently of one another during the pendency of the Merger. The restrictions in the Merger Agreement, which are subject to numerous exceptions, may not be adequate to prevent Black Hills from taking actions that are adverse to NorthWestern or its stockholders.

NorthWestern will incur significant transaction and other costs in connection with the Merger.

NorthWestern has incurred and expects to incur additional significant costs associated with the Merger, including transaction fees and costs of combining the operations of the two companies. Additional unanticipated costs also may be incurred in the integration of the businesses of NorthWestern and Black Hills. Any net benefit from any anticipated elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not be achieved in the near term or at all. Transaction costs could have a material adverse impact on the results of operations of NorthWestern, and the failure to achieve the anticipated benefits and efficiencies from the Merger, or the incurrence of additional expenses, could have a material adverse impact on the results of operations of the combined company and its ability

to pay dividends after closing. In turn, the current or future market value of NorthWestern Common Stock or other securities could be adversely impacted.

Uncertainties associated with the Merger may cause a loss of management personnel and other key employees of NorthWestern and Black Hills, which could adversely affect the future business and operations of the combined company following the Merger.

Each of NorthWestern and Black Hills depends on the experience and industry knowledge of its officers and other key employees to execute its business plans. The success of the combined company after the Merger will depend in part on its ability to retain key management personnel and other key employees. Current and prospective employees of NorthWestern and Black Hills may experience uncertainty about their roles within the combined company following the Merger or other concerns regarding the timing and completion of the Merger or the operations of the combined company following the Merger, any of which may have an adverse effect on the ability of NorthWestern and Black Hills to retain or attract key management and other key personnel. If NorthWestern or Black Hills is unable to retain personnel, including NorthWestern's or Black Hills' key management, who are critical to the future operations of the companies, NorthWestern and Black Hills could face disruptions in their operations, loss of existing customers, loss of key information, expertise or know-how and unanticipated additional recruitment and training costs. In addition, the loss of key NorthWestern and Black Hills personnel could diminish the anticipated benefits of the Merger. No assurance can be given that the combined company, following the Merger, will be able to retain or attract key management personnel and other key employees of NorthWestern and Black Hills to the same extent that NorthWestern and Black Hills have previously been able to retain or attract their own employees.

The business relationships of NorthWestern and Black Hills may be subject to disruption due to uncertainty associated with the Merger, which could have a material effect on the business, financial condition, cash flows and results of operations of NorthWestern or Black Hills pending the combined company and following the Merger.

Parties with which NorthWestern or Black Hills do business may experience uncertainty associated with the Merger, including with respect to current or future business relationships with NorthWestern or Black Hills following the Merger. NorthWestern's and Black Hills' business relationships may be subject to disruption as customers, distributors, suppliers, vendors, landlords, joint venture participants and other third parties with whom they do business may attempt to delay or defer entering into new business relationships, negotiate changes in existing business relationships or consider entering into business relationships with parties other than NorthWestern or Black Hills following the Merger. These disruptions could have a material and adverse effect on the business, financial condition, cash flows and results of operations, of NorthWestern or Black Hills, regardless of whether the Merger is completed, as well as a material and adverse effect on the combined company's ability to realize the expected cost savings and other benefits of the Merger. The risk, and adverse effects, of any disruption could be exacerbated by a delay in completion of the Merger or termination of the Merger Agreement.

The Merger may not be accretive to NorthWestern's or Black Hills' earnings and may cause dilution to the combined company's earnings per share, which may negatively affect the current or future market price of NorthWestern Common Stock or other securities.

Expectations that the Merger will be accretive to earnings per share are based on preliminary estimates any of which may prove to be incorrect or may change materially. NorthWestern and Black Hills may encounter additional transaction and integration-related costs other than those they currently anticipate, may fail to realize all of the benefits anticipated in the Merger or may be subject to other factors that affect preliminary estimates or the ability of either company to realize operational efficiencies. Any of these factors could cause a decrease in NorthWestern's and Black Hills' earnings per share, or negatively affect the current or future market price of NorthWestern Common Stock or other securities.

If the Merger does not qualify as a "reorganization" within the meaning of Section 368(a) of the Code, certain NorthWestern stockholders may be required to pay substantial U.S. federal, state and/or local income taxes.

The Merger is intended to qualify as a "reorganization" within the meaning of Section 368(a) of the Code, and it is a condition to each party's obligation to complete the Merger that it receive an opinion from counsel, dated as of the closing date of the Merger, to the effect that, on the basis of facts, representations and assumptions set forth or referred to in such opinion, the Merger will qualify as a "reorganization" within the meaning of Section 368(a) of the Code. However, the foregoing opinions of counsel will each be based on, among other things, the law in effect as of the date of the opinions, certain representations made by NorthWestern and Black Hills and certain assumptions, all of which must be consistent with the state of facts existing at the time of the Merger. If there is a change in law after the date of the opinions, or if any of these representations and assumptions are, or become, inaccurate or incomplete, an opinion may be invalid, and the conclusions reached therein could be jeopardized. In addition, no ruling has been or will be sought from the U.S. Internal Revenue Service

(IRS) as to the U.S. federal income tax consequences of the Merger and the other transactions contemplated by the Merger Agreement. There can be no assurance that the IRS will not assert, or that a court will not sustain, a position contrary to the conclusion set forth in any such opinion that the Merger will qualify as a "reorganization" within the meaning of Section 368(a) of the Code.

If the Merger does not qualify as a "reorganization" within the meaning of Section 368(a) of the Code, each NorthWestern stockholder will recognize gain or loss, for U.S. federal—and applicable state and local—income tax purposes equal to the value of the Black Hills stock received in the Merger (plus any cash received in respect of fractional shares) minus the stockholder's adjusted tax basis in the stockholder's NorthWestern stock. Depending on the amount of gain, if any, that is recognized, a NorthWestern stockholder that is subject to U.S. federal, state, or local income taxes may incur a significant income tax liability.

NorthWestern and/or Black Hills may be subject to litigation challenging the Merger while it is pending, and an unfavorable judgment or ruling in any such lawsuits could prevent or delay the consummation of the Merger and/or result in substantial costs.

Lawsuits in connection with the Merger while it is pending may be filed against NorthWestern, Black Hills, any parties to the Merger Agreement and/or their respective directors and officers, which could prevent or delay the consummation of the Merger and/or result in additional costs to us. The ultimate resolution of any such lawsuit cannot be predicted with certainty, and an adverse ruling in any such lawsuit may cause the Merger to be delayed or not to be completed and/or result in additional costs to NorthWestern and Black Hills, which could cause NorthWestern and Black Hills not to realize some or all of the anticipated benefits of the Merger. The defense or settlement of any lawsuit that remains unresolved at the time the Merger is consummated may adversely affect the combined company's business, financial condition, results of operations and cash flows. NorthWestern cannot currently predict the outcome of or reasonably estimate the possible loss or range of loss from any such lawsuit.

Risks Relating to the Combined Company Following Completion of the Merger

Failure to successfully combine the businesses of NorthWestern and Black Hills in the expected time frame or at all may adversely affect the future results of the combined company, and, consequently, the value of the Black Hills common stock to be received by the NorthWestern shareholders in the Merger.

The success of the Merger will depend, in part, on the ability of the combined company to realize in a timely fashion the anticipated benefits and efficiencies from combining the businesses of NorthWestern and Black Hills. The process of integration may reveal that benefits and efficiencies are less than anticipated and may result in additional expenses, all of which could reduce the anticipated benefits of the Merger.

Achieving the anticipated benefits of the Merger is subject to a number of uncertainties, including:

- whether United States federal and state public utility, antitrust and other regulatory authorities whose approval is required to complete the Merger impose conditions on the Merger, which may have an adverse effect on the combined company, including its ability to achieve the anticipated benefits of the Merger;
- the ability of the two companies to combine certain of their operations or take advantage of expected growth opportunities;
- general market and economic conditions;
- general competitive factors in the marketplace; and
- higher than expected costs required to achieve the anticipated benefits of the Merger.

Failure to achieve the anticipated benefits and efficiencies from the Merger, or the occurrence of additional expenses, could have a material adverse impact on the results of operations of the combined company and its ability to pay dividends after closing. In turn, the market value of the combined company's common stock could be adversely impacted.

NorthWestern stockholders will have a reduced ownership and voting interest after the Merger and will exercise less influence over management.

It is currently anticipated that NorthWestern stockholders and Black Hills stockholders will hold approximately 44 percent and 56 percent, respectively, of the combined company's common stock then-issued and outstanding after the completion of the Merger. Consequently, NorthWestern stockholders, as a group, will have reduced ownership and voting power in the combined company compared to their current ownership and voting power in NorthWestern. As a result of the reduced ownership percentages, current NorthWestern stockholders will have less influence on the management and policies of the combined company than they had with NorthWestern. Further, provisions of the Merger Agreement will result in individuals designated by Black Hills, and not previously subject to a vote of NorthWestern stockholders, holding six out of eleven positions on the combined company board of directors and there will be changes to the management of the combined company.

The market price of the combined company's Common Stock after the completion of the Merger may be affected by factors different from those that historically have affected or currently affect NorthWestern Common Stock.

Upon completion of the Merger, NorthWestern stockholders who receive Merger consideration will become holders of Black Hills Common Stock, which will trade on the NYSE or other mutually-agreeable exchange under a new name and ticker to be announced. NorthWestern's business differs from that of Black Hills and certain adjustments may be made to the combined company as a result of the Merger. The financial position of the combined company after completion of the Merger may differ from NorthWestern's financial position before the completion of the Merger, and the results of operations and/or cash flows of the combined company after the completion of the Merger may be affected by factors different from those currently affecting the financial position or results of operations and/or cash flows of NorthWestern and Black Hills, respectively. Accordingly, the market price of the combined company's common stock after the completion of the Merger may be affected by factors different from those currently affecting the market prices of NorthWestern Common Stock and Black Hills Common Stock, respectively, in the absence of the Merger. In addition, general fluctuations in stock markets could adversely affect the market for, or liquidity of, the combined company's common stock, regardless of the combined company's actual operating performance.

The failure to integrate the businesses and operations of NorthWestern and Black Hills successfully in the expected time frame may adversely affect the combined company's future results.

NorthWestern and Black Hills have operated and, until the completion of the Merger, will continue to operate independently. Following the completion of the Merger, their respective businesses may not be integrated successfully. It is possible that the integration process could result in the loss of key NorthWestern employees or key Black Hills employees; the loss of customers, service providers, vendors or other business counterparties, the disruption of either company's or both companies' ongoing businesses, inconsistencies in standards, controls, procedures and policies, potential unknown liabilities and unforeseen expenses, delays, or regulatory conditions associated with and following completion of the Merger; or higher-than-expected integration costs and an overall post-completion integration process that takes longer than originally anticipated. Specifically, the following challenges, among others, must be addressed in integrating the operations of NorthWestern and Black Hills in order to realize the anticipated benefits of the Merger:

- combining the companies' operations and corporate functions and the resulting difficulties associated with managing a larger, more complex, diversified business;
- combining the businesses of NorthWestern and Black Hills in a manner that permits the combined company to achieve the cost savings and operating synergies anticipated to result from the Merger;
- avoiding delays in connection with the completion of the Merger or the integration process;
- integrating personnel from the two companies and minimizing the loss of key employees;
- identifying and eliminating redundant functions and assets;
- harmonizing the companies' operating practices, employee development and compensation programs, internal controls and other policies, procedures and processes;
- maintaining existing agreements with customers, service providers, vendors and other business counterparties and avoiding delays in entering into new agreements with prospective customers, service providers, vendors and other business counterparties;
- addressing possible differences in business backgrounds, corporate cultures and management philosophies;
- consolidating the companies' operating, administrative and information technology infrastructure and financial systems; and
- establishing the combined company's headquarters in Rapid City, South Dakota.

In addition, at times the attention of certain members of either company's or both companies' management and resources may be focused on completion of the Merger and the integration of the businesses of the two companies and diverted from day-to-day business operations or other opportunities that may be beneficial, which may disrupt each company's ongoing operations and the operations of the combined company. Furthermore, following the Merger, the board of directors and executive leadership of the combined company will consist of former directors from each of NorthWestern and Black Hills and former executive officers from each of NorthWestern and Black Hills, respectively. Combining the boards of directors and management teams of each company into a single board and a single management team could require the reconciliation of differing priorities and philosophies.

Each of NorthWestern and Black Hills may have liabilities that are not known to the other party.

Each of NorthWestern and Black Hills may have liabilities that the other party failed, or was unable, to discover in the course of performing its respective due diligence investigations. NorthWestern and Black Hills may learn additional information about the other party that materially adversely affects it, such as unknown or contingent liabilities and liabilities related to compliance with applicable laws. As a result of these factors, the combined company may incur additional costs and expenses and may be forced to later write-down or write-off assets, restructure operations or incur impairment or other charges that could result in the combined company reporting losses. Even if NorthWestern's and Black Hills' respective due diligence has identified certain risks, unexpected risks may arise and previously known risks may materialize in a manner not consistent with its expectations. If any of these risks materialize, this could adversely affect the combined company's financial condition and results of operations and could contribute to negative market perceptions about, or price movements of, the combined company's common stock following the Merger.

Each of NorthWestern and Black Hills and their respective subsidiaries has substantial amounts of indebtedness. Consequently, the combined company will have substantial indebtedness following the Merger. As a result, the rating of the combined company's indebtedness could be downgraded, and it may be difficult for the combined company to pay or refinance its debts or take other actions, and the combined company may need to divert its cash flow from operations to debt service payments.

The combined company's debt service obligations with respect to this indebtedness could have an adverse impact on its earnings and cash flows for as long as the indebtedness is outstanding.

The combined company's indebtedness could also have important consequences to holders of the common stock of the combined company. For example, it could:

- make it more difficult for the combined company to pay or refinance its debts as they become due during adverse economic and industry conditions because any decrease in revenues could cause the combined company to not have sufficient cash flows from operations to make its scheduled debt payments;
- require a substantial portion of the combined company's cash flows from operations to be used for debt service payments, thereby reducing the availability of its cash flow to fund working capital, capital expenditures, acquisitions, dividend payments and other general corporate purposes;
- result in a downgrade in the rating of the combined company's indebtedness, which could limit its ability to borrow additional funds or increase the interest rates applicable to its indebtedness;
- increase the risk of default on debt obligations of the combined company;
- limit the flexibility of the combined company in planning for or reacting to changes in its business and the industry in which it operates;
- increase the exposure of the combined company to a rise in interest rates, which would generate greater interest expense or the costs of obtaining applicable interest rate fluctuation hedges; or
- require that additional or more stringent terms, conditions or covenants be placed on the combined company.

There can be no assurance that the combined company will be able to repay or refinance such borrowings and obligations.

In addition, the Merger will result in NorthWestern becoming a wholly owned subsidiary of Black Hills. The combined company may decide to incur additional indebtedness at subsidiaries of Black Hills, which could have an effect on outstanding securities, including because such subsidiary indebtedness is "structurally senior" to the indebtedness of its parent company with respect to the assets of such subsidiary.

The combined company may fail to realize all of the anticipated benefits of the Merger.

The success of the Merger will depend, in part, on the combined company's ability to realize the anticipated benefits and cost savings from combining Black Hills' and NorthWestern's businesses and operational synergies. The anticipated benefits and cost savings of the Merger may not be realized fully or at all, may take longer to realize than expected, may not be realized or could have other adverse effects that are not foreseen, in which case, among other things, the Merger may not be accretive to free cash flow and may not generate significant discretionary cash flow to return to shareholders via share buybacks or other means. Some of the assumptions that NorthWestern and Black Hills have made, such as the achievement of the anticipated benefits related to the geographic, commodity and asset diversification and the expected size, scale, inventory and financial strength of the combined company, may not be realized. The integration process may, for each of NorthWestern and Black Hills, result in the loss of key employees, the disruption of ongoing businesses or inconsistencies in standards, controls, procedures and policies. In addition, there could be potential unknown liabilities and unforeseen expenses associated with the Merger that could adversely impact the combined company.

The future results of the combined company following the Merger will suffer if the combined company does not effectively manage its expanded operations.

Following the Merger, the size, geographic footprint and complexity of the combined company will increase significantly compared to the business of each of NorthWestern and Black Hills. The combined company's future success will depend, in part, upon its ability to manage this expanded business, which will pose substantial challenges for management, including challenges related to the management and monitoring of new operations and geographies and associated increased costs and complexity. The combined company may also face increased scrutiny from, and/or additional regulatory requirements of, governmental authorities as a result of the significant increase in the size, geographic footprint and complexity of its business. There can be no assurances that the combined company will be successful or that it will realize the expected operating efficiencies, cost savings or other benefits currently anticipated from the Merger.

There is no guarantee that the combined company will declare and pay dividends following the Merger.

Although each of NorthWestern and Black Hills has returned capital to its respective stockholders in the past, including through cash dividends on their respective shares of common stock, the board of directors of the combined company may determine not to declare dividends or use other means to return capital to its stockholders in the future or may reduce the amount, proportion or rate of capital returned to its stockholders through dividends or other means in the future. Decisions on whether, when, by what means and in what amounts to return capital to its stockholders will remain in the discretion of the board of directors of the combined company (as reconstituted following the Merger). Any dividend payment or share

repurchase amounts will be determined by the board of directors of the combined company from time to time, and it is possible that the board of directors of the combined company may increase or decrease the amount of dividends paid or shares repurchased in the future, or determine not to declare dividends and/or repurchase shares in the future, at any time and for any reason. We expect that any such decisions will depend on the combined company's financial condition, results of operations, cash balances, cash requirements, future prospects, the outlook for commodity prices and other considerations that the board of directors of the combined company deems relevant, including, but not limited to:

- whether the combined company has enough discretionary cash flow to return capital to its stockholders due to its cash requirements, capital spending plans, cash flows or financial position;
- the combined company's desire to maintain or improve the credit ratings on its debt; and
- applicable restrictions under South Dakota law. Stockholders should be aware that they have no contractual or other legal right to dividends that have not been declared.

The combined company is expected to record a significant amount of goodwill as a result of the Merger, and such goodwill could become impaired in the future.

Accounting standards in the United States require that one party to the Merger be identified as the acquirer. In accordance with these standards, the Merger will be accounted for as an acquisition of NorthWestern's Common Stock by Black Hills and will follow the acquisition method of accounting for business combinations. NorthWestern's assets and liabilities will be consolidated with those of Black Hills on the combined company's financial statements. The excess of the consideration transferred over the fair values of NorthWestern's assets and liabilities will be recorded as goodwill.

The combined company will be required to assess goodwill for impairment at least annually. To the extent goodwill becomes impaired, the combined company may be required to incur material charges relating to such impairment. Such a potential impairment charge could have a material impact on the combined company's future operating results and statements of financial position which may, in turn, have a material adverse effect on the trading price or liquidity of the combined company's securities.

The combined company's ability to utilize NorthWestern's and/or Black Hills' historic net operating loss carryforwards and certain other tax attributes may be limited.

As of December 31, 2025, NorthWestern had U.S. federal net operating loss carryforwards (NOLs) of approximately $452.2 million, which do not expire. As of December 31, 2025, Black Hills had NOLs of approximately $380.1 million, which also do not expire. However, the NOLs of each of NorthWestern and Black Hills can only be used to offset 80% of U.S. federal taxable income. The combined company's ability to utilize these NOLs and other tax attributes to reduce future taxable income following the closing of the Merger depends on many factors, including its future income, which cannot be assured, and which will be determined after the Merger on a consolidated basis with that of NorthWestern and Black Hills. It is possible that the amount of NOLs and other tax attributes that the combined company is able to utilize in any tax period ending after the closing of the Merger may be less than the amount that NorthWestern and Black Hills together (or either of them separately) would have been able to use had the Merger not taken place.

Additionally, Section 382 of the Code (Section 382) and Section 383 of the Code generally impose an annual limitation on the amount of NOLs and certain other tax attributes that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of such corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change occurs with respect to NorthWestern and/or Black Hills, utilization of NorthWestern and/or Black Hills' NOLs would be subject to an annual limitation under Section 382, generally determined by multiplying (1) the fair market value of its stock at the time of the ownership change by (2) the long-term tax-exempt rate published by the IRS for the month in which the ownership change occurs, subject to certain adjustments. Any unused annual limitation may be carried over to later years.

The completion of the Merger may cause NorthWestern and/or Black Hills to undergo an ownership change under Section 382, which would trigger a limitation (calculated as described above) on NorthWestern's ability to utilize its and/or Black Hills' historic NOLs and other tax attributes.

Future sales or issuances of Black Hills Common Stock could have a negative impact on the Black Hills Common Stock price.

Under the terms of the Merger Agreement, NorthWestern stockholders will receive a fixed exchange ratio of 0.98 shares of Black Hills Common Stock for each share of NorthWestern Common Stock they own at the close of the Merger. Based on the 61,422,945 shares of NorthWestern Common Stock outstanding as of January 26, 2026, Northwestern stockholders would receive approximately 60,194,486 shares of Black Hills Common Stock upon the closing of the Merger. The treatment of outstanding equity awards of each of NorthWestern and Black Hills will vary depending on the type of award, its terms and conditions, and determinations made or to be made by each company or its board of directors, but additional shares, or cash in respect of share equivalents, would be issued to settle equity awards, and such shares are not reflected in the share totals included in the preceding sentence. The Black Hills Common Stock that NorthWestern stockholders will receive upon the exchange of NorthWestern Common Stock for the Merger consideration or in settlement of outstanding equity awards generally may be sold immediately in the public market. It is possible that some former NorthWestern stockholders may seek to sell some or all of the shares of Black Hills Common Stock they receive as Merger consideration, and the Merger Agreement contains no restriction on the ability of former NorthWestern stockholders to sell such shares of Black Hills Common Stock following completion of the Merger. Other Black Hills stockholders may also seek to sell shares of Black Hills Common Stock held by them following completion of the Merger. These sales or other dispositions of a significant number of shares of Black Hills Common Stock (or the perception that such sales or other dispositions may occur), coupled with the increase in the outstanding number of shares of Black Hills Common Stock as a result of the Merger (as well as any increase resulting from future issuances of Black Hills Common Stock), may affect the market for Black Hills Common Stock in an adverse manner and may cause the price of Black Hills Common Stock to fall.

Future disclosures relating to the Merger may not align with investor expectations.

In connection with the Merger, Black Hills filed a registration statement on Form S-4, including a prospectus and joint proxy statement for the NorthWestern stockholders' meeting and the Black Hills stockholders' meeting. Information contained in such registration statement and other future disclosures relating to the Merger, which include (among other things) detailed background about the process leading the Merger, prospective financial information reviewed by the NorthWestern and Black Hills board of directors in connection with the Merger, and updated historical financial information of NorthWestern and Black Hills and pro forma financial information of the combined company, may not align with investor expectations. Such disclosures, the anticipation of such disclosures, or reactions to such disclosures could have an adverse effect on the business of NorthWestern and trading price or liquidity of NorthWestern Common Stock or other securities. Persons making investment decisions about NorthWestern securities prior to such disclosures will be required to do so without the benefit of such information and with the risk that such information may not align with their expectations or that it may have an unexpected impact on NorthWestern or the trading price or liquidity of its securities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 1C. CYBERSECURITY

Cybersecurity Risk

As a fully integrated electric and gas utility, we operate and participate in regional markets and are interconnected with other entities. The operation of these systems depends on information technology systems we own and operate as well as third party systems and service providers. Strategic business partners are also leveraged to support our mission. As an operator of critical infrastructure, nefarious actors may find us a valuable target if they wish to disrupt our operations and negatively impact our customers. The systems and partnerships described above are all potential targets for a cyber-incident. Any significant interruption or failure of our information systems due to cyber-attacks or incidents could hinder our ability to fulfill our critical business functions. This could adversely affect our business, our financial condition, operating results or liquidity. Through the year ending on December 31, 2025, there have been no cybersecurity incidents that have had a material impact, or any impact, on our business strategy, operations, or financial condition.

Risk Management and Strategy

We utilize a comprehensive, defense in depth approach to cybersecurity risk, which helps us to continually assess, identify and manage enterprise-wide material cybersecurity risks. Our cybersecurity risk management is integrated into our overall Enterprise Risk Management (ERM) process and is reviewed at least quarterly. Our cybersecurity strategy focuses on maintaining the confidentiality, integrity and availability of data. We leverage frameworks established by the National Institute of Standards and Technology and the Center for Information Security for our information and cybersecurity governance program. We have a comprehensive cybersecurity threat detection and monitoring program for our technology and network infrastructure, which leverages various systems, processes, and operational measures to monitor, detect, and respond to cyber incidents. Our cybersecurity processes, including our threat detection, monitoring, and response protocols are subject to ongoing vulnerability testing, and comparison to industry practices. An Incident Response and Disaster Recovery Plan is maintained and exercised. The plan includes a process to identify, protect, detect, respond to and recover from cybersecurity threats and incidents. Resiliency and recoverability are paramount in the plan. This includes a clearly defined escalation process within the plan to ensure management and the Board of Directors are notified if an incident or series of events warrant escalation.

Our strategy includes employee training and awareness on cybersecurity risks and related best practices, simulated phishing campaigns, required password complexity, the use of multi-factor authentication, information security protocols, modern end point protection against threats, patching strategy, the execution of tabletop exercises on a periodic basis, established policies and protocols for cyber incident response planning and reporting, and ongoing internal cybersecurity testing.

As part of engaging a new third party provider, we assess their security standards, require security terms and conditions and work with risk management to ensure insurance coverage is adequate for the exposure risk. Service providers and vendors must adhere to security requirements such as security incident or data breach notification and response protocols, appropriate data encryption requirements, and data disposal. Our cyber incident monitoring process includes dialog with any third party or business partner potentially impacted by a disclosed incident. In addition, we leverage third party consultants to perform penetration (PEN) studies. These independent third party assessments provide valuable insight to enhance our cybersecurity posture.

Board Governance

Our Board of Directors reviews the cybersecurity program through risk review and cybersecurity reporting on at least a quarterly basis. The Audit Committee oversees our ERM program, including cybersecurity protocols. The Safety, Environmental, Technology and Operations (SETO) Committee provides oversight and review of technology policy and strategy as it relates to cybersecurity issues impacting company operations. Both the Audit Committee and the SETO Committee include Directors with diverse experience in technology, finance, enterprise risk, and security providing effective assessment and oversight of cybersecurity risk. Of note, one member of the Board has bolstered their understanding of technology and security issues by obtaining a certificate in cybersecurity oversight.

Roles and Responsibilities of Management

Our cyber security team, which reports to the Vice President - Technology, has primary responsibility for cybersecurity strategy and assessing cyber risk. The Vice President - Technology is responsible for informing the Chief Executive Officer and other Officers, as necessary, about cybersecurity incidents, covering prevention, detection, mitigation, and remediation efforts as they are detected by the cyber security team. Collectively, our cyber security team holds numerous industry certifications related to cybersecurity and have experience in desktop support, networking, application administration and programming.

ITEM 2. PROPERTIES

Our material properties include electric generating facilities, electric transmission and distribution lines, and natural gas production, transmission and distribution lines, which are described in Item 1 under Electric Operations and Natural Gas Operations. Substantially all of our NW Corp Montana electric and natural gas assets are subject to the lien of NW Corp's Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of NWE Public Service's South Dakota Mortgage Bond indenture.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 20 - Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information is about costs or potential costs that may be material to our financial results.

ITEM 4. MINE SAFETY DISCLOSURES

None

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, which is traded under the ticker symbol NWE, is listed on the Nasdaq Stock Market. As of February 6, 2026, there were approximately 1,268 common stockholders of record.

The following table contains monthly information about our repurchase of equity securities for the three months ended December 31, 2025:

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
October 1, 2025 - October 31, 2025	—	$ —	—	—
November 1, 2025 - November 30, 2025	—	—	—	—
December 1, 2025 - December 31, 2025	3,129	67.87	—	—
Total	3,129	$ 67.87	—	—

(1) Shares were acquired under the share withholding provisions of the Amended and Restated Equity Compensation Plan for payment of taxes associated with the vesting of equity compensation awards.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following includes a discussion of our results of operations and cash flows for the year ended December 31, 2025 compared to the year ended December 31, 2024, on both a consolidated basis and on a segment basis. For a discussion of our financial results and cash flows for the year ended December 31, 2024 compared with the year ended December 31, 2023, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2024.

This discussion should be read in conjunction with our Consolidated Financial Statements and related notes contained elsewhere in this Annual Report on Form 10-K. For additional information related to our segments, see Note 22 - Segment and Related Information, to the Consolidated Financial Statements.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Utility Margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. We define Utility Margin as Operating Revenues less fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion) as presented in our 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. The following discussion includes a reconciliation of Utility Margin to Gross Margin, the most directly comparable GAAP measure.

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

OVERVIEW

NorthWestern Energy Group, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 850,300 customers in Montana, South Dakota, Nebraska, and Yellowstone National Park. Our operations in Montana and Yellowstone National Park are conducted through our subsidiary, NW Corp, and our operations in South Dakota and Nebraska are conducted through our subsidiary, NWE Public Service. As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2025, 2024 and 2023. Following is a discussion of our strategy and significant trends.

On August 18, 2025, we entered into the Merger Agreement with Black Hills and Merger Sub that provides for an all-stock merger of equals between NorthWestern and Black Hills. The Merger Agreement provides for Merger Sub to merge with and into NorthWestern, with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of Black Hills, which would assume the new corporate name of Bright Horizon Energy as the resulting parent company of the combined corporate group. The Merger will combine the strengths of both companies, resulting in an organization with greater scale, financial stability, and operational expertise. It is designed to create a stronger, more resilient energy company focused on delivering safe, reliable, and affordable energy solutions to customers. Under the provisions of ASC Topic 805, which requires the identification of an acquirer in a business combination, Black Hills is the accounting acquirer. Pursuant to the Merger Agreement, at the effective time of the Merger, each share of common stock of NorthWestern issued and outstanding as of immediately prior to closing will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of Black Hills Common Stock. See Note 3 - Pending Merger with Black Hills Corporation to the Consolidated Financial Statements included herein for additional information regarding this pending Merger.

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

- Infrastructure investment focused on a stronger and smarter grid to improve the customer experience, while enhancing grid reliability and safety. This includes automation in customer meters, distribution and substations that enables the use of proven new technologies.

- Investing in and integrating supply resources that balance reliability, cost, capacity, and sustainability considerations with more predictable long-term commodity prices.

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

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

In 2025, approximately 52 percent of our owned and long-term contracted resources originated from carbon-free resources, compared to approximately 41 percent for the total U.S. electric power industry. We are committed to providing customers with reliable and affordable electric and natural gas services while also being good stewards of the environment. Towards this end, our efforts towards a carbon-free future are outlined through our goal to achieve net zero carbon emissions by 2050. Our vision for the future builds on the progress we have made, including our hydroelectric system in Montana, which is 100 percent carbon free and is readily available capacity. For us, wind generation is a close second and continues to grow. While utility-scale solar energy has not been a significant portion of our energy mix to date, we expect solar to further evolve along with advances in energy storage. We are committed to working with our customers and communities to help them achieve their sustainability goals and add new technology on our system.

HOW WE PERFORMED IN 2025 COMPARED TO OUR 2024 RESULTS

	Year Ended December 31, 2025 vs. 2024		
	Income Before Income Taxes	Income Tax Benefit (Expense)	Net Income
	(in millions)		
December 31, 2024	$ 214.7	$ 9.4	$ 224.1
*Variance in **revenue** and fuel, purchased supply, and direct transmission expense[1] items impacting net income:*			
Base Rates	93.3	(23.6)	69.7
Electric transmission revenue	14.0	(3.5)	10.5
Production tax credits, offset within income tax benefit (expense)	6.6	(6.6)	—
Montana natural gas transportation	4.8	(1.2)	3.6
Electric retail volumes	4.3	(1.1)	3.2
Natural gas retail volumes	2.0	(0.5)	1.5
Montana property tax tracker collections	(14.2)	3.6	(10.6)
Non-recoverable Montana electric supply costs	(7.3)	1.8	(5.5)
Other	0.1	0.0	0.1
*Variance in **expense** items[2] impacting net income:*			
Operating, maintenance, and administrative	(37.7)	9.5	(28.2)
Non-cash regulatory disallowance of certain YCGS capital costs	(30.9)	7.8	(23.1)
Depreciation	(21.9)	5.5	(16.4)
Interest expense	(18.7)	4.7	(14.0)
Merger-related costs	(9.3)	—	(9.3)
Property and other taxes not recoverable within trackers	(2.1)	0.5	(1.6)
Release of unrecognized tax benefits - current year	—	7.4	7.4
Release of unrecognized tax benefits - prior year	—	(16.9)	(16.9)
Prior year Gas repairs safe harbor method change	—	(7.0)	(7.0)
Other	(10.1)	3.7	(6.4)
December 31, 2025	$ 187.6	$ (6.5)	$ 181.1
Change in Net Income			$ (43.0)

(1) Exclusive of depreciation and depletion shown separately below.
(2) Excluding fuel, purchased supply, and direct transmission expense.

Consolidated net income in 2025 was $181.1 million as compared with $224.1 million in 2024. This decrease was primarily due to higher operating expenses, including a non-cash charge for the regulatory disallowance of certain YCGS capital costs resulting from the MPSC's final order on our rate review, merger-related costs, and depreciation, interest expense, Montana property tax tracker collections, non-recoverable Montana electric supply costs, and higher income tax expense due to a less favorable uncertain tax position release and a prior year income tax benefit from a gas repairs safe harbor method change. These were partly offset by higher rates, electric transmission revenue, natural gas transportation revenues, and retail volumes.

Montana Rate Review

In July 2024, we filed a Montana electric and natural gas rate review with the MPSC requesting an annual increase to electric and natural gas utility rates. In December 2025, the MPSC issued a final order approving the natural gas settlement agreement and partial electric settlement agreement. Among other things, the approved partial electric settlement agreement provides for the deferral and annual recovery of incremental operating costs related to wildfire mitigation and insurance expenses through the Wildfire Mitigation Balancing Account.

The details of this final order are set forth below:

Returns, Capital Structure & Revenue Increase Resulting From Final Order ($ in millions)

	Electric	Natural Gas
Return on Equity (ROE)	9.65 %	9.60 %
Equity Capital Structure	47.84 %	47.84 %
Base Rates	$ 105.5	$ 18.0
PCCAM[1][2]	(94.5)	n/a
Property Tax (tracker base adjustment)[1]	(1.8)	0.1
Total Revenue Increase Through Final Order	$ 9.2	$ 18.1

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(2) This PCCAM reduction of $94.5 million represents the reduction in revenue at the previously approved 2021 PCCAM base of $208.3 million using the 2023 Montana rate review test period loads.

The final order provides for an update to the PCCAM by adjusting the base costs from $208.3 million to $119.0 million. It also suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC. Within this final order, the MPSC disallowed a portion of the capital costs related to the construction of YCGS. As a result, in the fourth quarter of 2025 we recorded a $30.9 million non-cash charge for the regulatory disallowance within Operating and maintenance on the Consolidated Statements of Income and a corresponding reduction to Property, plant, and equipment, net on the Consolidated Balance Sheets. As of December 31, 2025, we have deferred $7.7 million of base rate revenues collected that will be refunded to customers.

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

Montana Large-Load Tariff

The MPSC requested information on our plan to serve potential large-load customers and related resource adequacy issues. We responded in March 2025, outlining our policy and legal positions, emphasizing the importance of economic development for Montana and our commitment to serving our existing customers. We expect to submit a filing with the MPSC during the first half of 2026 to address data center development discussed below, incorporating rate design that prevents cost shifting of infrastructure upgrades needed to serve large-load customers to other retail customers.

Data Center Development

In July 2025, we entered into a nonbinding letter of intent with Quantica Infrastructure to evaluate the transmission infrastructure and generation resources needed to support their proposed need. We had previously disclosed, in December 2024, two separate nonbinding letters of intent with Sabey Data Centers (Sabey) and Atlas Power Holdings LLC (Atlas) to provide electric supply services for data centers being developed in Montana. The combined energy service requirement associated with these letters of intent is currently expected to be 175 megawatts beginning in late 2027, or earlier, with growth of up to 1,100 megawatts or more by 2030. We have signed development agreements with both Sabey and Atlas and are working with each of these parties to execute electric service agreements.

Resources and regulatory mechanisms 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 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 would provide a near-term cost-recovery mechanism expected to largely offset 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.

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. 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. We expect this rate approval to be effective in the first quarter of 2026. If our request for rates effective January 1, 2026 is not approved, we could incur refund liability for contract revenues received during the unauthorized period.

Generation Capacity in South Dakota

The SPP has recently updated its resource accreditation and PRM requirements in response to growing reliability concerns. As a result, SPP is requiring additional accredited capacity by 2030 to meet the updated PRM targets. In October 2025, we submitted a project with the SPP under their Expedited Resource Adequacy Study program for the construction of a 131 MW natural gas generating facility located in Aberdeen, South Dakota, to meet regional capacity needs by 2030. Anticipated costs for this project are approximately $300.0 million.

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.

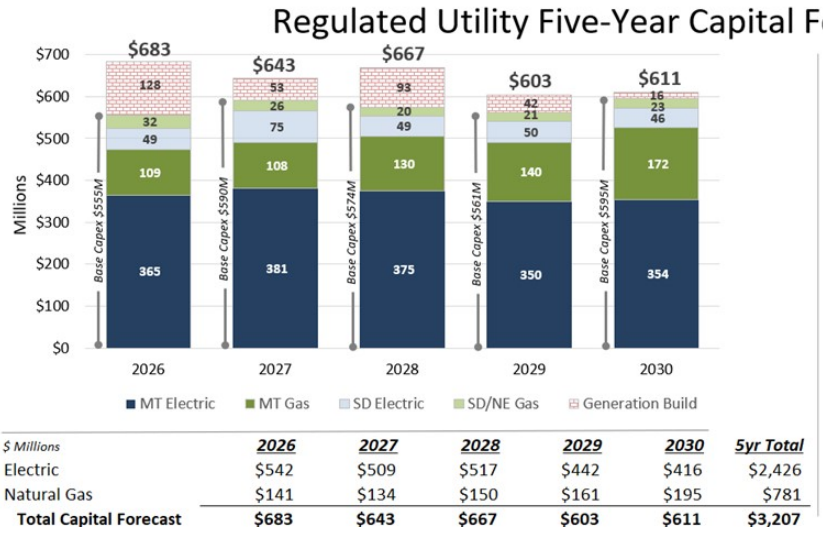
Montana Wildfire Risk Mitigation

The Montana Legislature approved House Bill 490 in April 2025. It precludes common law strict liability claims for damages related to wildfire and electric activities or wildfire mitigation activities; establishes a statutory standard of care,

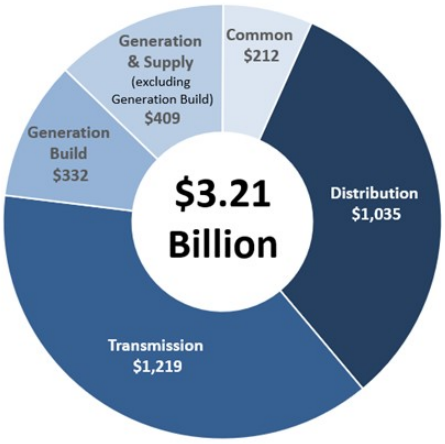
supplanting common law causes of action and other theories of recovery; and creates a rebuttable presumption that an electric facilities provider acted reasonably if it substantially followed an approved wildfire mitigation plan. The legislation also defines the availability of damages by allowing noneconomic personal injury damages only when there is bodily injury and punitive damages only when an injured party proves by clear and convincing evidence that an electric facilities provider's actions were grossly negligent or intentional. The MPSC approved our wildfire mitigation plan in November 2025. The wildfire mitigation plan for the Colstrip transmission system was submitted to the MPSC on November 7, 2025, and we anticipate a decision in the first quarter of 2026.

SIGNIFICANT INFRASTRUCTURE INVESTMENTS AND INITIATIVES

Our estimated capital expenditures for the next five years, including our electric and natural gas transmission and distribution and electric generation infrastructure investment plan, are as follows (in 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**



Electric Supply Resource Plans - Our energy resource plans identify portfolio resource requirements including potential investments. For additional information related to our electric supply resource plans, see Item 1. Business, where we discuss electric resource planning for our Montana and South Dakota jurisdictions.

Distribution and Transmission Modernization and Maintenance - The primary goals of our infrastructure investments are to reverse the trend in aging infrastructure, maintain reliability, proactively manage safety, build capacity into the system, and prepare our network for the adoption of new technologies. We are taking a proactive and pragmatic approach to replacing these assets while also evaluating the implementation of additional technologies to prepare the overall system for smart grid applications. Approximately $2.3 billion, or 70 percent, of our capital forecast above is projected to be spent on our distribution and transmission system. In 2025, we completed the installation, which began in 2021, of automated metering infrastructure in Montana.

RESULTS OF OPERATIONS

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

Factors Affecting Results of Operations

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

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

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

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

OVERALL CONSOLIDATED RESULTS

Year Ended December 31, 2025 Compared with Year Ended December 31, 2024

Consolidated net income in 2025 was $181.1 million as compared with $224.1 million in 2024, a decrease of $43.0 million. This decrease was primarily due to higher operating expenses, including a non-cash charge for the regulatory disallowance of certain YCGS capital costs resulting from the MPSC's final order on our rate review, merger-related costs, and depreciation, interest expense, Montana property tax tracker collections, non-recoverable Montana electric supply costs, and higher income tax expense due to a less favorable uncertain tax position release and a prior year income tax benefit from a gas repairs safe harbor method change. These were partly offset by higher rates, electric transmission revenue, natural gas transportation revenues, and retail volumes.

Consolidated gross margin in 2025 was $484.3 million as compared with $460.8 million in 2024, an increase of $23.5 million or 5.1 percent. This increase was primarily due to higher rates, electric transmission revenue, natural gas transportation revenues, and retail volumes. These were partly offset by higher operating expenses, including a non-cash charge for the regulatory disallowance of certain YCGS capital costs resulting from the MPSC's final order on our rate review and depreciation, Montana property tax tracker collections, and non-recoverable Montana electric supply costs.

	Electric		Natural Gas		Total	
	2025	2024	2025	2024	2025	2024
			(in millions)			
Reconciliation of gross margin to utility margin:						
Operating Revenues	$1,270.0	$1,200.7	$ 340.6	$ 313.2	$1,610.6	$1,513.9
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	306.6	329.6	103.2	104.2	409.8	433.8
Less: Operating and maintenance	224.4	171.7	60.5	56.1	284.9	227.8
Less: Property and other taxes	140.9	126.5	41.2	37.4	182.1	163.9
Less: Depreciation and depletion	208.6	190.0	40.9	37.6	249.5	227.6
Gross Margin	**389.5**	**382.9**	**94.8**	**77.9**	**484.3**	**460.8**
Operating and maintenance	224.4	171.7	60.5	56.1	284.9	227.8
Property and other taxes	140.9	126.5	41.2	37.4	182.1	163.9
Depreciation and depletion	208.6	190.0	40.9	37.6	249.5	227.6
Utility Margin[1]	**$ 963.4**	**$ 871.1**	**$ 237.4**	**$ 209.0**	**$1,200.8**	**$1,080.1**

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

	Year Ended December 31,			
	2025	2024	Change	% Change
	(in millions)			
Utility Margin				
Electric	$ 963.4	$ 871.1	$ 92.3	10.6 %
Natural Gas	237.4	209.0	28.4	13.6
Total Utility Margin[1]	**$ 1,200.8**	**$ 1,080.1**	**$ 120.7**	**11.2 %**

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

Consolidated utility margin in 2025 was $1,200.8 million as compared with $1,080.1 million in 2024, an increase of $120.7 million, or 11.2 percent.

Primary components of the change in utility margin include the following (in millions):

	Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income	
Base Rates	$ 93.3
Electric transmission revenue due to market conditions and rates	14.0
Montana natural gas transportation	4.8
Electric retail volumes	4.3
Natural gas retail volumes ($4.2 million due to acquisition of Energy West Operations)	2.0
Montana property tax tracker collections	(14.2)
Non-recoverable Montana electric supply costs	(7.3)
Other	0.1
Change in Utility Margin Impacting Net Income	**97.0**
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property and other taxes	16.3
Production tax credits, offset in income tax expense	6.6
Operating expenses recovered in revenue, offset in operating and maintenance expense	0.8
Change in Items Offset Within Net Income	**23.7**
Increase in Consolidated Utility Margin[(1)]	**$ 120.7**

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

Electric retail volumes were driven by favorable weather in South Dakota impacting residential demand, higher Montana commercial demand, and customer growth in all jurisdictions, partly offset by unfavorable weather in Montana, lower commercial demand in South Dakota, and lower industrial demand. Natural gas retail volumes were driven by the acquisition of Energy West, favorable weather in South Dakota and Nebraska, higher commercial demand, and customer growth in all jurisdictions, partly offset by unfavorable weather in Montana.

Under the PCCAM, net supply costs higher or lower than the PCCAM base rate (PCCAM Base) (excluding QF costs) were allocated 90 percent to Montana customers and 10 percent to shareholders. For the twelve months ended December 31, 2025, we under-collected supply costs of $73.9 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $8.2 million (10 percent of the PCCAM Base cost variance). For the twelve months ended December 31, 2024, we under-collected supply costs of $8.0 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $0.9 million (10 percent of the PCCAM Base cost variance). As part of the MPSC's final order on our Montana electric rate review they suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC.

	Year Ended December 31,			
	2025	2024	Change	% Change
	(in millions)			
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)				
Operating and maintenance	$ 284.9	$ 227.8	$ 57.1	25.1 %
Administrative and general	158.2	137.4	20.8	15.1
Property and other taxes	182.3	163.9	18.4	11.2
Depreciation and depletion	249.5	227.6	21.9	9.6
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 874.9**	**$ 756.7**	**$ 118.2**	**15.6 %**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $874.9 million in 2025, as compared with $756.7 million in 2024. Primary components of the change include the following (in millions):

	Operating Expenses 2025 vs. 2024
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income	
Non-cash regulatory disallowance of certain YCGS capital costs	$ 30.9
Depreciation expense due to plant additions and higher depreciation rates	21.9
Electric generation maintenance	9.9
Merger-related costs, primarily including consulting and legal fees	9.3
Wildfire mitigation expense, partly offset by higher base revenues	8.9
Insurance expense, primarily due to increased wildfire risk premiums	7.8
Labor and benefits[(1)]	7.6
Technology implementation and maintenance	3.5
Property and other taxes not recoverable within trackers	2.1
Uncollectible accounts	1.1
Litigation outcome (Pacific Northwest Solar)	(2.4)
Non-cash impairment of alternative energy storage investment	(1.7)
Other	3.0
Change in Items Impacting Net Income	**101.9**
Operating Expenses Offset Within Net Income	
Property and other taxes recovered in trackers, offset in revenue	16.3
Deferred compensation, offset in other income	2.1
Operating and maintenance expenses recovered in trackers, offset in revenue	0.8
Pension and other postretirement benefits, offset in other income[(1)]	(2.9)
Change in Items Offset Within Net Income	**16.3**
Increase in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$ 118.2**

(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.

Consolidated operating income in 2025 was $325.8 million as compared with $323.3 million in 2024. This increase was primarily due to new rates, electric transmission revenue, natural gas transportation revenues, and retail volumes. These were partly offset by higher operating, administrative, and general costs, including a non-cash charge for the regulatory disallowance of certain YCGS capital costs resulting from the MPSC's final order on our rate review and merger-related costs, depreciation, Montana property tax tracker collections, and non-recoverable Montana electric supply costs.

Consolidated interest expense in 2025 was $150.4 million, as compared with $131.7 million in 2024. This increase was due to higher borrowings and interest rates, partly offset by lower capitalization of AFUDC.

Consolidated other income in 2025 was $12.1 million, as compared with $23.0 million in 2024. This decrease was primarily due to lower capitalization of AFUDC, a prior year reversal of $2.3 million from a previously disclosed CREP penalty due to a favorable legal ruling, and a $1.3 million expense current year accrual related to an estimated penalty for the CREP informed by a recent MPSC ruling, partly offset by an increase of $2.5 million driven by a prior year non-cash impairment of an alternative energy storage equity investment.

Consolidated income tax expense in 2025 was $6.5 million, as compared to an income tax benefit of $9.4 million in 2024. Our effective tax rate for the twelve months ended December 31, 2025 was 3.5 percent as compared with (4.4)

percent for the same period of 2024. As further discussed in Note 14 - Income Taxes, income tax expense for the twelve months ended December 31, 2025, includes a $10.4 million benefit related to a reduction in our unrecognized tax benefits, inclusive of $3.0 million of previously accrued interest ($7.4 million net of interest). Income tax benefit for the twelve months ended December 31, 2024, includes a $21.0 million benefit related to a reduction in our unrecognized tax benefits, inclusive of $4.1 million of previously accrued interest ($16.9 million net of interest). Additionally, during the twelve months ended December 31, 2024, we filed a tax accounting method change with the IRS consistent with the guidance for natural gas transmission and distribution property. This resulted in an income tax benefit of $7.0 million during 2024, related to repair costs that were previously capitalized for tax purposes in the 2022 and prior tax years.

We currently estimate our effective tax rate will range between 14.0 percent to 18.0 percent in 2026. Based on the significant NOL income tax position we have, we anticipate paying minimal cash for income taxes into 2029.

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

	Year Ended December 31,			
	2025		2024	
	(in dollars)	(in percent)	(in dollars)	(in percent)
Income before income taxes	$187.6		$214.7	
Income tax calculated at federal statutory rate	39.4	21.0 %	45.1	21.0 %
State income tax, net of federal provision	(1.5)	(0.8)	0.4	0.2
Tax Credits				
Production tax credits	(5.9)	(3.2)	(11.1)	(5.2)
Other	0.7	0.4	0.7	0.3
Impact of utility ratemaking on income taxes				
Flow-through repairs deductions	(31.0)	(16.5)	(23.1)	(10.8)
Amortization of excess deferred income taxes	(3.2)	(1.7)	(2.9)	(1.4)
AFUDC, net	(1.3)	(0.7)	(2.6)	(1.2)
Plant and depreciation of flow through items	16.8	9.0	9.4	4.4
Gas repairs safe harbor method change	—	—	(7.0)	(3.3)
Changes in Unrecognized Tax Benefits				
Release of unrecognized tax benefits	(7.4)	(4.0)	(16.9)	(7.9)
Interest and penalties	(3.0)	(1.6)	(1.5)	(0.7)
Nontaxable and nondeductible items	2.9	1.5	0.4	0.2
Other	0.0	0.1	(0.3)	0.0
	(32.9)	(17.5)%	(54.5)	(25.4)%
Income Tax Expense (Benefit) and Effective Tax Rate	$ 6.5	3.5 %	$ (9.4)	(4.4)%

Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

ELECTRIC OPERATIONS

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

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

Year Ended December 31, 2025 Compared with Year Ended December 31, 2024

	Revenues		Change		MWHs		Avg. Customer Counts	
	2025	2024	$	%	2025	2024	2025	2024
	(in thousands)							
Montana	$ 406,643	$ 398,790	$ 7,853	2.0 %	2,834	2,804	334,011	328,420
South Dakota	77,894	70,012	7,882	11.3	583	557	51,787	51,467
Residential	**484,537**	**468,802**	**15,735**	**3.4**	**3,417**	**3,361**	**385,798**	**379,887**
Montana	408,530	408,977	(447)	(0.1)	3,216	3,197	77,305	75,878
South Dakota	120,108	111,813	8,295	7.4	1,061	1,093	13,190	13,084
Commercial	**528,638**	**520,790**	**7,848**	**1.5**	**4,277**	**4,290**	**90,495**	**88,962**
Industrial	43,128	46,637	(3,509)	(7.5)	2,789	2,924	80	80
Other[1]	34,510	32,811	1,699	5.2	147	146	28,564	28,608
Total Retail Electric	**$1,090,813**	**$1,069,040**	**$ 21,773**	**2.0 %**	**10,630**	**10,721**	**504,937**	**497,537**
Regulatory amortization	58,265	24,908	33,357	133.9				
Transmission	111,024	97,052	13,972	14.4				
Wholesale and Other	9,854	9,701	153	1.6				
Total Revenues	**$1,269,956**	**$1,200,701**	**$ 69,255**	**5.8 %**				
Fuel, purchased supply and direct transmission expense[2]	**306,569**	**329,578**	**(23,009)**	**(7.0)**				
Utility Margin[3]	**$ 963,387**	**$ 871,123**	**$ 92,264**	**10.6 %**				

(1) Included within this line is our lighting customer class, which we have historically counted each lighting district as one customer. We have retrospectively modified our customer counts to now reflect each lighting service as a customer as that better aligns with the MWH usage of this customer class.
(2) Exclusive of depreciation and depletion.
(3) Non-GAAP financial measure. See “Non-GAAP Financial Measure” above. Also see "Overall Consolidated Results" above for reconciliation of gross margin to utility margin.

	Cooling Degree Days			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana	392	485	460	19% cooler	15% cooler
South Dakota	938	778	751	21% warmer	25% warmer

	Heating Degree Days			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana[1]	7,044	7,033	7,486	remained flat	6% warmer
South Dakota	6,943	6,501	7,696	7% colder	10% warmer

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

The following summarizes the components of the changes in electric utility margin for the years ended December 31, 2025 and 2024 (in millions):

	Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income	
Base rates	$ 71.8
Electric transmission revenue due to market conditions and rates	14.0
Retail volumes	4.3
Montana property tax tracker collections	(10.8)
Non-recoverable Montana electric supply costs	(7.3)
Other	(0.1)
Change in Utility Margin Items Impacting Net Income	**71.9**
Utility Margin Items Offset Within Net Income	
Property and other taxes recovered in revenue, offset in property and other taxes	12.7
Production tax credits, offset in income tax expense	6.6
Operating expenses recovered in revenue, offset in operating and maintenance expense	1.1
Change in Items Offset Within Net Income	**20.4**
Increase in Utility Margin[1]	**$ 92.3**

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

Electric retail volumes were driven by favorable weather in South Dakota impacting residential demand, higher Montana commercial demand, and customer growth in all jurisdictions, partly offset by unfavorable weather in Montana, lower commercial demand in South Dakota, and lower industrial demand.

For the twelve months ended December 31, 2025, we under-collected supply costs of $73.9 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $8.2 million (10 percent of the PCCAM Base cost variance). For the twelve months ended December 31, 2024, we under-collected supply costs of $8.0 million resulting in an increase to our under collection of costs, and recorded a decrease in pre-tax earnings of $0.9 million (10 percent of the PCCAM Base cost variance). As part of the MPSC's final order on our Montana electric rate review they suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC.

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

NATURAL GAS OPERATIONS

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

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

Year Ended December 31, 2025 Compared with Year Ended December 31, 2024

	Revenues		Change		Dekatherms		Avg. Customer Counts	
	2025	2024	$	%	2025	2024	2025	2024
	(in thousands)							
Montana	$ 120,830	$ 110,215	10,615	9.6 %	14,339	13,749	201,728	185,644
South Dakota	28,948	26,884	2,064	7.7	3,032	2,709	42,952	42,577
Nebraska	25,733	21,205	4,528	21.4	2,414	2,294	37,970	37,958
Residential	**175,511**	**158,304**	**17,207**	**10.9**	**19,785**	**18,752**	**282,650**	**266,179**
Montana	68,722	59,925	8,797	14.7	8,691	7,782	28,380	26,164
South Dakota	21,574	18,069	3,505	19.4	3,303	2,791	7,586	7,383
Nebraska	13,784	11,432	2,352	20.6	1,738	1,664	5,114	5,056
Commercial	**104,080**	**89,426**	**14,654**	**16.4**	**13,732**	**12,237**	**41,080**	**38,603**
Industrial	2,439	1,041	1,398	134.3	2,140	147	241	237
Other	1,350	1,352	(2)	(0.1)	197	207	218	197
Total Retail Gas	**$ 283,380**	**$ 250,123**	**$ 33,257**	**13.3 %**	**35,854**	**31,343**	**324,189**	**305,216**
Regulatory amortization	(305)	19,017	(19,322)	(101.6)				
Transportation, wholesale and other	57,528	44,057	13,471	30.6				
Total Revenues	**$ 340,603**	**$ 313,197**	**$ 27,406**	**8.8 %**				
Fuel, purchased supply and direct transmission expense[1]	**103,186**	**104,238**	**(1,052)**	**(1.0)**				
Utility Margin[2]	**$ 237,417**	**$ 208,959**	**$ 28,458**	**13.6 %**				

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

	Heating Degree Days			2025 as compared with:	
	2025	2024	Historic Average	2024	Historic Average
Montana[1]	7,207	7,265	7,697	1% warmer	6% warmer
South Dakota	6,943	6,501	7,696	7% colder	10% warmer
Nebraska	5,719	5,241	6,061	9% colder	6% warmer

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

The following summarizes the components of the changes in natural gas utility margin for the years ended December 31, 2025 and 2024 (in millions):

		Utility Margin 2025 vs. 2024
Utility Margin Items Impacting Net Income		
Base rates	$	21.5
Montana natural gas transportation		4.8
Retail volumes ($4.2 million due to acquisition of Energy West Operations)		2.0
Montana property tax tracker collections		(3.4)
Other		0.2
Change in Utility Margin Impacting Net Income		**25.1**
Utility Margin Items Offset Within Net Income		
Property and other taxes recovered in revenue, offset in property and other taxes		3.6
Operating expenses recovered in revenue, offset in operating and maintenance expense		(0.3)
Change in Items Offset Within Net Income		**3.3**
Increase in Utility Margin[(1)]	**$**	**28.4**

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

Natural gas retail volumes were driven by the acquisition of Energy West, favorable weather in South Dakota and Nebraska, higher commercial demand, and customer growth in all jurisdictions, partly offset by unfavorable weather in Montana.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. For NorthWestern Energy Group, liquidity is primarily provided through its revolving credit facility and dividends from its utility operating subsidiaries, NW Corp and NWE Public Service. These subsidiaries are subject to certain restrictions that may limit the amount of their dividend distributions. See Note 18 - Common Stock to the Consolidated Financial Statements for more information regarding these dividend restrictions.

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

As of December 31, 2025, our total consolidated net liquidity was approximately $229.8 million, including $8.8 million of cash and $221.0 million of revolving credit facility availability with no letters of credit outstanding.

Cash Flows

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

	Year Ended December 31,	
	2025	2024
Operating Activities		
Net income	$ 181.1	$ 224.1
Non-cash adjustments to net income	289.0	213.5
Changes in working capital	(61.4)	(18.9)
Other noncurrent assets and liabilities	(14.2)	(11.9)
Cash Provided by Operating Activities	**394.5**	**406.8**
Investing Activities		
Property, plant and equipment additions	(524.5)	(549.3)
Acquisition of Energy West Operations	(35.9)	—
Other investing activity	(10.3)	(5.2)
Cash Used in Investing Activities	**(570.7)**	**(554.5)**
Financing Activities		
Issuance of long-term debt	602.1	215.0
Issuance of short-term borrowings	50.0	100.0
Repayments on long-term debt	(300.0)	(100.0)
Dividends on common stock	(161.4)	(158.6)
Line of credit (repayments) borrowings , net	(9.0)	95.0
Financing costs	(4.5)	(1.1)
Treasury stock activity	0.7	1.2
Cash Provided by Financing Activities	**177.9**	**151.5**
Net Increase in Cash, Cash Equivalents, and Restricted Cash	**$ 1.7**	**$ 3.8**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 29.0	$ 25.2
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 30.7**	**$ 29.0**

Operating Activities

As of December 31, 2025, cash, cash equivalents, and restricted cash were $30.7 million as compared with $29.0 million as of December 31, 2024. Cash provided by operating activities totaled $394.5 million for the year ended December 31, 2025 as compared with $406.8 million for the year ended December 31, 2024. The changes in cash flows from operating activities generally follow the results of operations, as discussed above in the consolidated results of operations for the year ended December 31, 2025, and are affected by changes in working capital. The decrease in cash provided by operating activities is primarily due to merger transaction costs, lower collections of accounts receivable balances due to timing of colder weather, and an increase in our net cash outflows for energy supply costs, as shown in the table below, partly offset by the proceeds from production tax credits transferred.

Net under-collected energy supply costs (in millions)

	Beginning of year	End of year	Net cash inflows (outflows)
2024	$ 7.8	$ 5.9	$ 1.9
2025	$ 5.9	$ 44.8	$ (38.9)
		Increase in net cash outflows	$ (40.8)

Investing Activities

Cash used in investing activities totaled $570.7 million during the year ended December 31, 2025, as compared with $554.5 million during 2024. Plant additions during 2025 include capital maintenance additions of approximately $372.7 million and capacity related capital expenditures of approximately $151.8 million. Plant additions during 2024 included capital maintenance additions of approximately $324.0 million and capacity related capital expenditures of approximately $225.3 million. During the year ended December 31, 2025, we completed the acquisition of the Energy West Operations for $35.9 million. See Note 4 - Acquisition of Energy West Operations to the Consolidated Financial Statements included herein for additional information regarding this acquisition. As discussed above in the "Significant Infrastructure Investments and Initiatives" section, our capital expenditures are forecasted to be $683.0 million in 2026.

Financing Activities

Cash provided by financing activities totaled $177.9 million during the year ended December 31, 2025 as compared with $151.5 million during the year ended December 31, 2024. During the year ended December 31, 2025, cash provided by financing activities reflects proceeds from the issuance of long-term debt of $602.1 million and short-term borrowings of $50.0 million, partly offset by repayment of $300.0 million of Montana and South Dakota First Mortgage bonds, payment of dividends of $161.4 million, and net repayments under our revolving lines of credit of $9.0 million. During the year ended December 31, 2024, cash provided by financing activities reflects proceeds from the issuance of long-term debt of $215.0 million, short-term borrowings of $100.0 million, and net issuances under our revolving lines of credit of $95.0 million, partly offset by payment of dividends of $158.6 million and repayment of $100.0 million of Montana First Mortgage Bonds.

Cash Requirements and Capital Resources

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

Our material cash requirements are also related to investment in our business through our capital expenditure program, which is discussed above in the "Significant Infrastructure Investments and Initiatives" section. Our capital expenditures are forecasted to be $683 million in 2026, $643 million in 2027, and $667 million in 2028. 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. The actual amount of capital

expenditures is subject to certain factors including the impact that a material change in operations, available financing, supply chain issues, or inflation could impact our current liquidity and ability to fund capital resource requirements. Events such as these could cause us to defer a portion of our planned capital expenditures, as necessary. To fund our strategic growth opportunities, we evaluate the additional capital need in balance with debt capacity and equity issuances that would be intended to allow us to maintain investment grade ratings.

Short-term Borrowings

For further information on our short-term borrowings, see Note 12 - Short-Term Borrowings and Credit Arrangements to the Consolidated Financial Statements included herein. NorthWestern Energy Group has $150.0 million of short-term borrowings maturing in 2026, which we intend to refinance.

Credit Facilities

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

For further information on our credit facilities, see Note 12 - Short-Term Borrowings and Credit Arrangements to the Consolidated Financial Statements included herein.

The following table presents additional information about borrowings under our revolving credit facilities during the year ended December 31, 2025 (in millions):

Amount outstanding at year end	$	404.0
Daily average amount outstanding	$	291.0
Maximum amount outstanding	$	415.0
Minimum amount outstanding	$	36.0

As of February 6, 2026, availability under our revolving credit facilities was approximately $229.0 million, and there were no letters of credit outstanding.

Long-term Debt and Equity

We generally issue long-term debt to refinance other long-term debt maturities and borrowings under our revolving credit facilities, as well as to fund long-term capital investments and strategic opportunities. We have $105.0 million of long-term debt maturing in 2026, which we intend to refinance.

For further information on our long-term debt, see Note 13 - Long-Term Debt and Finance Leases to the Consolidated Financial Statements included herein.

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

For further information regarding equity, see Note 18 - Common Stock to the Consolidated Financial Statements included herein.

Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of February 6, 2026, our current ratings with these agencies are as follows:

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

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

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

Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. With the exception of maturities of long-term debt, we anticipate funding these obligations through cash flows from operations. The following table summarizes our contractual cash obligations and commitments as of December 31, 2025. See additional discussion in Note 20 - Commitments and Contingencies to the Consolidated Financial Statements.

	Total	2026	2027	2028	2029	2030	Thereafter
				(in thousands)			
Long-term debt[1]	$ 3,298,660	$ 105,000	$ —	$ 583,660	$ 33,000	$ 650,000	$ 1,927,000
Finance leases	1,865	1,865	—	—	—	—	—
Short-term borrowings	150,000	150,000	—	—	—	—	—
Estimated pension and other postretirement obligations[2]	51,067	12,643	10,206	9,806	9,306	9,106	N/A
QF liability[3]	168,592	55,393	56,665	42,400	14,134	—	—
Supply and capacity contracts[4]	3,883,865	424,471	343,663	340,135	341,470	316,667	2,117,459
Contractual interest payments on debt[5]	1,515,754	142,813	137,144	140,276	109,172	96,182	890,167
Commitments for significant capital projects[6]	51,111	51,111	—	—	—	—	$ —
Total Commitments[7]	$ 9,120,914	$ 943,296	$ 547,678	$ 1,116,277	$ 507,082	$ 1,071,955	$ 4,934,626

(1) Represents cash payments for long-term debt and excludes $12.7 million of debt discounts and debt issuance costs, net.
(2) We have estimated cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. The pension and other postretirement benefit estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(3) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $124 to $130 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $168.6 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $152.8 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts (exclusive of the qualifying facilities liability discussed above). These commitments range from one to 24 years.
The majority of our energy supply costs incurred under these contracts are recoverable through rate mechanisms, as further described in Note 6 - Regulatory Assets and Liabilities.

(5) Contractual interest payments include our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 5.07 percent on the outstanding balance through maturity of the credit facilities.
(6) Represents significant firm purchase commitments for construction of planned capital projects.
(7) The table above excludes potential tax payments related to unrecognized tax benefits as they are not practicable to estimate. Additionally, the table above excludes reserves for environmental remediation (See Note 20 - Commitments and Contingencies) and AROs (see Note 8 - Asset Retirement Obligations) as the amount and timing of cash payments may be uncertain.

Other Obligations - As a co-owner of Colstrip, we provided surety bonds of approximately $13.5 million and $15.8 million as of December 31, 2025 and 2024, respectively, to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Stations, Colstrip Montana (the AOC) as required by the MDEQ. As costs are incurred under the AOC, the surety bonds will be reduced.

CRITICAL ACCOUNTING ESTIMATES

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

We have identified the policies and related procedures below that contain accounting estimates that involve a significant level of estimation uncertainty and have had or are reasonably likely to have a material impact on our financial condition or results of operations.

Regulatory Assets and Liabilities

Our operations are subject to the provisions of ASC 980, *Regulated Operations* (ASC 980). Our regulatory assets are the probable future revenues associated with certain costs to be recovered from customers through the ratemaking process, including our estimate of amounts recoverable for natural gas and electric supply purchases. Regulatory liabilities are the probable future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. This accounting treatment is impacted by the uncertainties of our regulatory environment, anticipated future regulatory decisions and their impact. If any part of our operations becomes no longer subject to the provisions of ASC 980, or facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery, we would record a charge to earnings, which could be material. In addition, we would need to determine if there was any impairment to the carrying costs of the associated plant and inventory assets.

While we believe that our assumptions regarding future regulatory actions are reasonable, different assumptions could materially affect our results. See Note 6 - Regulatory Assets and Liabilities to the Consolidated Financial Statements for further discussion.

Pension and Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefits for eligible employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 16 - Employee Benefit Plans to the Consolidated Financial Statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics, rate of return on plan assets and other economic conditions, and various actuarial calculations, assumptions, and accounting mechanisms. As a result of these factors, significant portions of pension and other postretirement benefit costs recorded in any period do not reflect (and are generally greater than) the actual benefits provided to plan participants. Due to the complexity of these calculations, the long-term nature of the obligations, and the importance of the assumptions utilized, the determination of these costs is considered a critical accounting estimate.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

- Discount rates used in determining the future benefit obligations;
- Expected long-term rate of return on plan assets; and
- Mortality assumptions.

We review these assumptions on an annual basis and adjust them as necessary. The assumptions are based upon market interest rates, past experience and management's best estimate of future economic conditions.

We set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year projected benefit cash flow from our plans. Based on this analysis as of December 31, 2025, our discount rate for both NorthWestern Energy SD/NE Pension Plan and NorthWestern Energy MT Pension Plan is 5.20 percent and 5.65 percent, respectively.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Our expected long-term rate of return on assets assumptions are 4.96% percent and 6.3% percent on the NorthWestern Energy SD/NE Pension Plan and NorthWestern Energy MT Pension Plan, respectively, for 2026.

Cost Sensitivity

The following table reflects the sensitivity of pension costs to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate increase	0.25 %	$ 127	$ (6,446)
Discount rate decrease	(0.25)%	25	6,787
Rate of return on plan assets increase	0.25 %	(798)	N/A
Rate of return on plan assets decrease	(0.25)%	798	N/A

Accounting Treatment

We recognize the funded status of each plan as an asset or liability in the Consolidated Balance Sheets. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, which reduces the volatility of reported pension costs. If necessary, the excess is amortized over the average remaining service period of active employees.

Due to the various regulatory treatments of the plans, our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. Regulatory assets have been recognized for the obligations that will be included in future cost of service.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ significantly from these estimates.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. The uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the Consolidated Financial Statements. We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As of December 31, 2025, we have not recorded any unrecognized tax benefits. The resolution of tax matters in a particular future period could have a material impact on our provision for income taxes, results of operations and our cash flows. See Note 14 - Income Taxes to the Consolidated Financial Statements for further discussion.

NEW ACCOUNTING STANDARDS

See Note 2 - Significant Accounting Policies, to the Consolidated Financial Statements, included in Item 8 herein for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and credit exposure. Management has established comprehensive risk management policies and procedures to manage these market risks.

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facilities. Our credit facilities bear interest at rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points, plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points. As of December 31, 2025, we had $404.0 million in borrowings under our revolving credit facilities. A 1.0 percent increase in interest rates would increase our annual interest expense by approximately $4.0 million.

Commodity Price Risk

We are exposed to commodity price risk due to our reliance on market purchases to fulfill a portion of our electric and natural gas supply requirements. We also participate in the wholesale electric market to balance our supply of power from our own generating resources. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

As part of our overall strategy for fulfilling our electric and natural gas supply requirements, we employ the use of market purchases and sales, including forward contracts. These types of contracts are included in our supply portfolios and in some instances, are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. These contracts are part of an overall portfolio approach intended to provide price stability for consumers. As a regulated utility, our exposure to market risk caused by changes in commodity prices is mitigated because these commodity costs are included in our Montana, South Dakota and Nebraska cost tracking mechanisms and are recoverable from customers subject to a regulatory review for prudency.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. If counterparties seek financial protection under bankruptcy laws, we are exposed to greater financial risks. We are also exposed to counterparty credit risk related to providing transmission service to our customers under our OATT, under gas transportation agreements, and contracts for electricity sales in wholesale energy markets. We have risk management policies in place to limit our transactions to high quality counterparties. We monitor closely the status of our counterparties and take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial information, including the reports of independent registered public accounting firm and the quarterly financial information, required by this Item 8 is indexed in Item 15 of this Annual Report on Form 10-K and is hereby incorporated into this Item 8 by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation our principal executive officer and principal financial officer have concluded that, as of December 31, 2025, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

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

Management's Annual Report on Internal Control over Financial Reporting

The management of NorthWestern is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board regarding the preparation and fair presentation of published financial statements.

All internal controls over financial reporting, no matter how well designed, have inherent limitations, including the possibility of human error and the circumvention or overriding of controls. Therefore, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Our management, including our chief executive officer and chief financial officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2025. In making its assessment of internal control over financial reporting, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on our evaluation, management concluded that, as of December 31, 2025, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. Their report appears on page F-3.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2025, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading agreement" or "non-Rule 10b5-1 trading agreement," as each term is defined in Item 408(a) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors and corporate governance will be set forth in NorthWestern Energy Group's Proxy Statement for its 2026 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to our Executive Officers is included under "Information about our Executive Officers" in Item 1 of this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item will be set forth in NorthWestern Energy Group's Proxy Statement for its 2026 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item will be set forth in NorthWestern Energy Group's Proxy Statement for its 2026 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information concerning relationships and related transactions of the directors and officers of NorthWestern Energy Group and director independence will be set forth in NorthWestern Energy Group's Proxy Statement for its 2026 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information concerning fees paid to the principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34), for each of the last two years will be set forth in NorthWestern Energy Group's Proxy Statement for its 2026 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Consolidated Financial Statements.

The following items are included in Part II, Item 8 of this annual report on Form 10-K:

CONSOLIDATED FINANCIAL STATEMENTS:

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All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes thereto.

(2) Exhibits.

The exhibits listed below are hereby filed with the SEC, as part of this Annual Report on Form 10-K. Certain of the following exhibits have been previously filed with the SEC pursuant to the requirements of the Securities Act of 1933 or the Securities Exchange Act of 1934. Such exhibits are identified by the parenthetical references following the listing of each such exhibit and are incorporated by reference. We will furnish a copy of any exhibit upon request, but a reasonable fee may be charged to cover our expenses in furnishing such exhibit.

Exhibit Number	Description of Document
2.1(a)	Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(b)	Order Confirming the Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(c)	Agreement and Plan of Merger, dated October 2, 2023 by and among NorthWestern Corporation, NorthWestern Energy Group, Inc. and NorthWestern Energy Merger Company, dated as of October 2, 2023 (incorporated by reference to Exhibit 2(a) of NorthWestern Energy Group Inc.'s Current Report on Form 8-K, dated October 2, 2023).
2.1(d)	Colstrip Units 3&4 Interests Abandonment and Acquisition Agreement, dated as of January 16, 2023, by and between Avista Corporation and Northwestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated January 17, 2023, Commission File No. 1-10499).
2.1(e)	Colstrip Units 3&4 Interests Abandonment and Acquisition Agreement, dated as of July 30, 2024 by and between Northwestern Corporation and Puget Sound Energy Inc. (incorporated by reference to Exhibit 2.1 of NorthWestern Energy Group, Inc.'s Current Report on Form 8-K, dated July 30, 2024 Commission File No. 000-56598).
2.1(f)	Agreement and Plan of Merger, dated as of August 18, 2025, by and among Black Hills Corporation, NorthWestern Energy Group, Inc., and River Merger Sub Inc.(incorporated by reference to Exhibit 2.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated August 18, 2025, Commission File No. 000-56598).
3.1(a)	Amended and Restated Certificate of Incorporation of NorthWestern Energy Group, Inc., dated as of September 25, 2023 (incorporated by reference to Exhibit 3(a) of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated October 2, 2023).
3.2(b)	Amended and Restated Bylaws of NorthWestern Energy Group, Inc., dated as of September 29, 2023 (incorporated by reference to Exhibit 3(b) of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated October 2, 2023).
3.2(c)	Second Amended and Restated Bylaws of NorthWestern Energy Group, Inc., dated August 18, 2025 (incorporated by reference to Exhibit 10.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated August 18, 2025, Commission File No. 000-56598).
4.1(a)	First Mortgage and Deed of Trust, dated as of October 1, 1945, by The Montana Power Company in favor of Guaranty Trust Company of New York and Arthur E. Burke, as trustees (incorporated by reference to Exhibit 7(e) of The Montana Power Company's Registration Statement, Commission File No. 002-05927).
4.1(b)	Eighteenth Supplemental Indenture to the Mortgage and Deed of Trust, dated as of August 5, 1994 (incorporated by reference to Exhibit 99(b) of The Montana Power Company's Registration Statement on Form S-3, dated December 5, 1994, Commission File No. 033-56739).
4.1(c)	Twenty-Eighth Supplemental Indenture, dated as of October 1, 2009, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
4.1(d)	Twenty-Ninth Supplemental Indenture, dated as of May 1, 2010, among NorthWestern Corporation and The Bank of New York Mellon and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.1(e)	Thirtieth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon and Philip L. Watson, as trustees under the Mortgage and Deed of Trust dated as of October 1, 1945 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.1(f)	Thirty-First Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).

4.1(g)	Thirty-Second Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4(n) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(h)	Thirty-Third Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 14, 2014, Commission File No. 1-10499).
4.1(i)	Thirty-Fourth Supplemental Indenture, dated as of January 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4(p) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(j)	Thirty-Fifth Supplemental Indenture, dated as of June 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2015, Commission File No. 1-10499).
4.1(k)	Thirty-Seventh Supplemental Indenture, dated as of November 1, 2017, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 8, 2017, Commission File No. 1-10499).
4.1(l)	Thirty-Eighth Supplemental Indenture, dated as of June 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated July 2, 2019, Commission File No. 1-10499).
4.1(m)	Thirty-Ninth Supplemental Indenture, dated as of September 1, 2019, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 20, 2019, Commission File No. 1-10499).
4.1(n)	Fortieth Supplemental Indenture, dated as of April 1, 2020, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 15, 2020, Commission File No. 1-10499).
4.1(o)	Forty-Second Supplemental Indenture, dated as of March 1, 2023, between the Company and The Bank of New York Mellon and Mary Miselis, as trustees, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 30, 2023, Commission File No. 1-10499).
4.1(p)	Forty-third Supplemental Indenture, dated as of May 1, 2023, between the Company and The Bank of New York Mellon and Mary Miselis, as trustees. (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated June 5, 2023, Commission File No. 1-10499).
4.1(q)	Forty-fourth Supplemental Indenture, dated as of June 1, 2023, between NorthWestern Corporation and The Bank of New York Mellon and Mary Miselis, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2023, Commission File No. 1-10499).
4.1(r)	Forty-fifth Supplemental Indenture, dated as of March 1, 2024, between NW Corp and The Bank of New York Mellon and Dimple Gandhi, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated March 28, 2024, Commission File No. 000-56598).
4.1(s)	Forty-sixth Supplemental Indenture, dated as of March 1, 2025, between NorthWestern Corporation and The Bank of New York Mellon and Dimple Gandhi, as trustees. (incorporated by reference to Exhibit 4.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated March 27, 2025, Commission File No. 000-56598).
4.1(t)	Forty-seventh Supplemental Indenture, dated as of November 1, 2025, between NorthWestern Corporation and The Bank of New York Mellon and Dimple Gandhi, as trustees. (incorporated by reference to Exhibit 4.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated November 7, 2025, Commission File No. 000-56598).
4.2(a)	General Mortgage Indenture and Deed of Trust, dated as of August 1, 1993, from NorthWestern Corporation to The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4(a) of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 1993, Commission File No. 1-10499).

4.2(b)	Supplemental Indenture, dated as of November 1, 2004, by and between NorthWestern Corporation (formerly known as Northwestern Public Service Company) and JPMorgan Chase Bank (successor by merger to The Chase Manhattan Bank (National Association)), as Trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.5 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.2(c)	Ninth Supplemental Indenture, dated as of May 1, 2010, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.2(d)	Tenth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon, as trustees under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.2(e)	Eleventh Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.2(f)	Twelfth Supplemental Indenture, dated as of December 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2014, Commission File No. 1-10499).
4.2(g)	Thirteenth Supplemental Indenture, dated as of September 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 29, 2015, Commission File No. 1-10499).
4.2(h)	Fourteenth Supplemental Indenture, dated as of June 1, 2016, between the NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 21, 2016, Commission File No. 1-10499).
4.2(i)	Fifteenth Supplemental Indenture, dated as of September 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 6, 2016, Commission File No. 1-10499).
4.2(j)	Sixteenth Supplemental Indenture, dated as of April 1, 2020, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated May 15, 2020, Commission File No. 1-10499).
4.2(k)	Seventeenth Supplemental Indenture, dated as of March 1, 2023, between the Company and The Bank of New York Mellon, as trustee, (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 30, 2023, Commission File No. 1-10499).
4.2(l)	Eighteenth Supplemental Indenture, dated as of May 1, 2023, between the Company and The Bank of New York Mellon, as trustee. (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 1, 2023, Commission File No. 1-10499).
4.2(m)	Nineteenth Supplemental Indenture, dated as of June 1, 2023, between the Company and The Bank of New York Mellon, as trustee. (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 5, 2023, Commission File No. 1-10499).
4.2(n)	Twentieth Supplemental Indenture, dated as of January 1, 2024, between NWE Public Service and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1of NorthWestern Energy Group's Current Report on Form 8-K, dated January 2, 2024, Commission File No. 000-56598).
4.2(o)	Twenty-first Supplemental Indenture, dated as of March 1, 2024, between NWE Public Service and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Energy Group's Current Report on Form 8-K, dated March 28, 2024, Commission File No. 000-56598).
4.2(p)	Twenty-Second Supplemental Indenture, dated as of May 1, 2025, between NorthWestern Energy Public Service Corporation and The Bank of New York Mellon, as trustee. (incorporated by reference to Exhibit 4.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated May 7, 2025, Commission File No. 000-56598).
4.3(a)	Indenture, dated as of August 1, 2016, between City of Forsyth, Rosebud County, Montana and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(b)	Loan Agreement, dated as of August 1, 2016, between NorthWestern Corporation and the City of Forsyth, Montana, related to the issuance of City of Forsyth Pollution Control Revenue Bonds Series 2016 (incorporated by reference to Exhibit 4.2 of the Company's Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(c)	Bond Delivery Agreement, dated as of August 1, 2016, between NorthWestern Corporation and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.3 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).

4.3(d)	Thirty-Sixth Supplemental Indenture, dated as of August 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3(e)	Forty-First Supplemental Indenture, dated as of March 1, 2021, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated March 26, 2021, Commission File No. 1-10499).
4.3(f)	Indenture, dated as of June 1, 2023 between City of Forsyth, Rosebud County, Montana and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2023, Commission File No. 1-10499).
4.3(g)	Loan Agreement, dated as of June 1, 2023, by and between the City of Forsyth, Rosebud County, Montana, and NorthWestern Corporation (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2023, Commission File No. 1-10499).
4.3(h)	Bond Delivery Agreement, dated as of June 1, 2023, between NorthWestern Corporation and U.S. Bank Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.3 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2023, Commission File No. 1-10499).
4.3(i)	20th Supplemental Indenture, dated January 1, 2024 (incorporated by reference to Exhibit 4.1 of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated January 2, 2024).
4.5	Description of Securities (incorporated by reference to Exhibit 99(b) of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated October 2, 2023).
10.1(a) †	NorthWestern Corporation Officers Deferred Compensation Plan, as amended October 2, 2023. (incorporated by reference to Exhibit 10.1a of NorthWestern Energy Group's Report on Form 10-K for the year ended December 31, 2023, Commission File No. 000-56598).
10.1(b) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2020, Commission File No. 1-10499).
10.1(c) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2021, Commission File No. 1-10499).
10.1(d) †	NorthWestern Energy 2023 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2022, Commission File No. 1-10499).
10.1(e) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2022, Commission File No. 1-10499).
10.1(f) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated February 17, 2023, Commission File No. 1-10499).
10.1(g) †	Form of NorthWestern Corporation Restricted Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation’s Current Report on Form 8-K, dated February 17, 2023, Commission File No. 1-10499).
10.1(h) †	NorthWestern Energy Group, Inc., Deferred Compensation Plan for Non-Employee Directors, as amended and renamed effective October 2, 2023 (incorporated by reference to Exhibit 10.1(b) of NorthWestern Group Inc.’s Current Report on form 10-Q, dated October 27, 2023, Commission File No. 000-56598).
10.1(i) †	NorthWestern Energy Group Inc.'s 2024 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 20, 2023, Commission File No. 000-56598).
10.1(j) †	Form of 2024 Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Energy Group’s Current Report on Form 8-K, dated February 20, 2024, Commission File No. 000-56598).
10.1(k) †	Form of 2024 Restricted Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Energy Group’s Current Report on Form 8-K, dated February 20, 2024, Commission File No. 000-56598).
10.1(l) †	NorthWestern Corporation Amended and Restated Key Employee Severance Plan, as amended and restated effective April 25, 2024. (incorporated by reference to Exhibit 10.7 of NorthWestern Energy Group's Quarterly Report on Form 10-Q for the quarter ended March 31, 2024, Commission File No. 000-56598).
10.1(m) †	NorthWestern Energy Group, Inc. Amended and Restated Equity Compensation Plan, as amended and restated effective April 25, 2024. (incorporated by reference to Exhibit 10.8 of NorthWestern Energy Group's Quarterly Report on Form 10-Q for the quarter ended March 31, 2024, Commission File No. 000-56598).
10.1 (n) †	NorthWestern Energy Group Inc.'s 2025 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 12, 2024, Commission File No. 000-56598).

10.1 (o) †	Chief Executive Officer Agreement, dated August 18, 2025, between Black Hills Corporation and Brian B. Bird dated August 18, 2025 (incorporated by reference to Exhibit 10.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated August 18, 2025, Commission File No. 000-56598).
10.2(a)	Second Amended and Restated Credit Agreement, dated November 29, 2023 (incorporated by reference to Exhibit 10.1 of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated December 5, 2023).
10.2(b)	$200,000,000 Credit Agreement, dated November 29, 2023 (incorporated by reference to Exhibit 10.2 of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated December 5, 2023).
10.2 (c)	Term Loan Credit Agreement, dated April 12, 2024 (incorporated by reference to Exhibit 10.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated April 12, 2024, Commission File No. 000-56598).
10.2 (d)	Amendment No. 3 to Term Loan Credit Agreement and Lender Joinder Agreement. (incorporated by reference to Exhibit 10.1 of NorthWestern Energy Group's Current Report on Form 8-K, dated October 3, 2025, Commission File No. 000-56598).
10.3	Asset and Stock Transfer Agreement, dated December 27, 2023 (incorporated by reference to Exhibit 10.1 of Northwestern Energy Group Inc.'s Current Report on Form 8-K, dated January 2, 2024).
19	Policy for insider trading, dated October 2, 2023. (incorporated by reference to Exhibit 19 of Northwestern Energy Group Inc.'s Annual Report on Form 10-K, dated February 13, 2025).
21*	Subsidiaries of NorthWestern Group, Inc.
23*	Consent of Independent Registered Public Accounting Firm
24*	Power of Attorney (included on the signature page of this Annual Report on Form 10-K)
31.1*	Certification of President and Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
32.1*	Certification of Brian B. Bird pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Crystal Lail pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97	Policy for the recovery of erroneously awarded compensation (incorporated by reference to Exhibit 97 of the NorthWestern Energy Group, Inc.'s Report on Form 10-K for the year ended December 31, 2023, Commission File No. 000-56598)
101.INS*	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)	

† Management contract or compensatory plan or arrangement.
* Filed herewith.

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions or are not applicable, and, therefore, have been omitted.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

NorthWestern Energy Group, Inc.

February 12, 2026

By: /s/ BRIAN B. BIRD

Brian B. Bird

President and Chief Executive Officer

POWER OF ATTORNEY

We, the undersigned directors and/or officers of NorthWestern Energy Group, hereby severally constitute and appoint Brian B. Bird and Crystal D. Lail, and each of them with full power to act alone, our true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution and revocation, for each of us and in our name, place, and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, and hereby grant unto such attorneys-in-fact and agents, and each of them, the full power and authority to do each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as each of us might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their respective substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ LINDA G. SULLIVAN Linda G. Sullivan	Board Chair	February 12, 2026
/s/ BRIAN B. BIRD Brian B. Bird	President, Chief Executive Officer and Director (Principal Executive Officer)	February 12, 2026
/s/ CRYSTAL D. LAIL Crystal D. Lail	Vice President and Chief Financial Officer (Principal Financial Officer)	February 12, 2026
/s/ JEFFREY B. BERZINA Jeffrey B. Berzina	Controller (Principal Accounting Officer)	February 12, 2026
/s/ JAN R. HORSFALL Jan R. Horsfall	Director	February 12, 2026
/s/ BRITT E. IDE Britt E. Ide	Director	February 12, 2026
/s/ KENT T. LARSON Kent T. Larson	Director	February 12, 2026
/s/ DAVID L. GOODIN David L. Goodin	Director	February 12, 2026
/s/ MAHVASH YAZDI Mahvash Yazdi	Director	February 12, 2026
/s/ JEFFREY W. YINGLING Jeffrey W. Yingling	Director	February 12, 2026
/s/ SHERINA M. EDWARDS Sherina M. Edwards	Director	February 12, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NorthWestern Energy Group, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NorthWestern Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, cash flows and common shareholders' equity, for each of the three years in the period ended December 31, 2025, and the related notes and the schedule listed in the Index at Item 15 (collectively, referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters - Impact of Rate Regulation on the Financial Statements - Refer to Notes 2, 5 and 6 to the financial statements

Critical Audit Matter Description

The Company accounts for the financial effects of regulation in accordance with ASC 980, *Regulated Operations.* This guidance allows for the recording of a regulatory asset or liability for certain costs or credits which otherwise would be recognized in the statement of income or comprehensive income based on an expectation that the cost will be recovered or returned in future rates.

The Company is subject to rate regulation by federal and state utility regulatory agencies (collectively, the “Commissions”), which have jurisdiction over the Company’s electric and natural gas distribution rates in Montana, South Dakota and Nebraska. The Company assesses the probability of recovery of regulatory assets and the obligations arising from regulatory liabilities on a quarterly basis. Probability estimates incorporate numerous factors, including recent rate making decisions, historical precedents for similar matters, the regulatory environments in which the Company operates, and the impact that incurred costs may have on customers.

While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve full recovery of the costs of providing utility service or full recovery of all amounts invested in the utility business and a reasonable return on that investment.

As a result , we identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include the recording of regulatory assets for certain costs which otherwise would be recognized in the statement of income or comprehensive income based on an expectation that the costs will be recovered in future rates and the recording of regulatory liabilities for certain credits which would otherwise be recognized in the statement of income or comprehensive income based on an expectation that the amount will be returned to customers in future rates. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments requires specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the recognition of amounts as regulatory assets or liabilities the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates and the related disclosures in the notes to the financial statements.

- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, filings made by the Company, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.

- We assessed management's conclusion regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 11, 2026
We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NorthWestern Energy Group, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NorthWestern Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2025, of the Company and our report dated February 11, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Annual Report on Internal Control over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 11, 2026

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2025	2024	2023
Revenues			
Electric	$ 1,269,956	$ 1,200,701	$ 1,068,833
Gas	340,603	313,197	353,310
Total Revenues	1,610,559	1,513,898	1,422,143
Operating Expenses			
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	409,755	433,816	420,262
Operating and maintenance	284,924	227,836	220,524
Administrative and general	158,235	137,437	117,360
Property and other taxes	182,301	163,853	153,068
Depreciation and depletion	249,526	227,635	210,474
Total Operating Expenses	1,284,741	1,190,577	1,121,688
Operating Income	325,818	323,321	300,455
Interest Expense, net	(150,351)	(131,673)	(114,617)
Other Income, net	12,098	23,024	15,832
Income Before Income Taxes	187,565	214,672	201,670
Income Tax (Expense) Benefit	(6,473)	9,439	(7,539)
Net Income	$ 181,092	$ 224,111	$ 194,131
Average Common Shares Outstanding	61,381	61,293	60,321
Basic Earnings per Average Common Share	$ 2.95	$ 3.66	$ 3.22
Diluted Earnings per Average Common Share	$ 2.94	$ 3.65	$ 3.22

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2025	2024	2023
Net Income	$ 181,092	$ 224,111	$ 194,131
Other comprehensive income (loss), net of tax:			
Reclassification of net losses on derivative instruments	452	452	452
Postretirement medical liability adjustment	173	504	(262)
Foreign currency translation	18	(4)	2
Total Other Comprehensive Income (Loss)	643	952	192
Comprehensive Income	$ 181,735	$ 225,063	$ 194,323

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	As of December 31,	
	2025	2024
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,781	$ 4,283
Restricted cash	21,957	24,734
Accounts receivable, net	209,751	187,764
Inventories	132,506	122,940
Regulatory assets	92,937	39,851
Prepaid expenses and other	38,010	38,614
Total current assets	**503,942**	**418,186**
Property, plant, and equipment, net	6,738,849	6,398,275
Goodwill	367,635	357,586
Regulatory assets	772,634	764,414
Other noncurrent assets	76,631	59,063
Total Assets	**$ 8,459,691**	**$ 7,997,524**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 1,865	$ 3,596
Current portion of long-term debt	104,967	299,950
Short-term borrowings	150,000	100,000
Accounts payable	129,633	111,794
Accrued expenses and other	272,373	254,599
Regulatory liabilities	38,613	32,261
Total current liabilities	**697,451**	**802,200**
Long-term finance leases	—	1,865
Long-term debt	3,181,040	2,695,343
Deferred income taxes	733,064	663,430
Noncurrent regulatory liabilities	678,861	660,942
Other noncurrent liabilities	283,535	316,044
Total Liabilities	**5,573,951**	**5,139,824**
Commitments and Contingencies (Note 20)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 64,895,311 and 61,418,361, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	649	648
Treasury stock at cost	(97,503)	(97,394)
Paid-in capital	2,091,935	2,084,133
Retained earnings	896,720	877,017
Accumulated other comprehensive loss	(6,061)	(6,704)
Total Shareholders' Equity	**2,885,740**	**2,857,700**
Total Liabilities and Shareholders' Equity	**$ 8,459,691**	**$ 7,997,524**

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2025	2024	2023
OPERATING ACTIVITIES:			
Net Income	$ 181,092	$ 224,111	$ 194,131
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and depletion	249,526	227,635	210,474
Amortization of debt issuance costs, discount and deferred hedge gain	4,416	4,647	5,142
Stock-based compensation costs	6,985	4,721	5,176
Equity portion of AFUDC	(9,870)	(18,628)	(17,614)
(Gain) loss on disposition of assets	(82)	(61)	316
Regulatory disallowance of certain YCGS capital costs	30,895	—	—
Impairment of alternative energy storage investment	—	4,159	—
Deferred income taxes	7,118	(8,969)	6,584
Changes in current assets and liabilities:			
Accounts receivable	(20,483)	24,493	32,695
Inventories	(6,187)	(8,402)	(7,180)
Other current assets	632	(13,216)	2,644
Accounts payable	(4,351)	7,399	(54,722)
Accrued expenses	16,406	9,748	(3,377)
Regulatory assets	(53,746)	(10,109)	105,588
Regulatory liabilities	6,351	(28,842)	39,957
Other noncurrent assets and liabilities	(14,247)	(11,945)	(30,583)
Cash Provided by Operating Activities	394,455	406,741	489,231
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(524,456)	(549,244)	(566,889)
Acquisition of Energy West Operations	(35,938)	—	—
Investment in equity securities	(10,238)	(4,719)	(3,923)
Other investing activity	—	(500)	—
Cash Used in Investing Activities	(570,632)	(554,463)	(570,812)
FINANCING ACTIVITIES:			
Dividends on common stock	(161,389)	(158,589)	(154,050)
Proceeds from issuance of common stock, net	—	—	73,613
Issuance of long-term debt	602,077	215,000	300,000
Issuances of short-term borrowings	50,000	100,000	—
Repayments on long-term debt	(300,000)	(100,000)	—
Line of credit (repayments) borrowings , net	(9,000)	95,000	(132,000)
Treasury stock activity	709	1,192	1,069
Financing costs	(4,499)	(1,051)	(4,327)
Cash Provided by Financing Activities	177,898	151,552	84,305
Net Increase in Cash, Cash Equivalents, and Restricted Cash	1,721	3,830	2,724
Cash, Cash Equivalents, and Restricted Cash, beginning of period	29,017	25,187	22,463
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 30,738**	**$ 29,017**	**$ 25,187**

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
(in thousands, except per share data)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2022	**63,278**	**3,534**	**$ 633**	**$1,999,376**	**$ (98,392)**	**$ 771,414**	**$ (7,848)**	**$ 2,665,183**
Net income	—	—	—	—	—	194,131	—	194,131
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	2	2
Reclassification of net gains on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(262)	(262)
Stock based compensation	51	—	—	4,954	—	—	—	4,954
Issuance of shares	1,433	(21)	15	74,423	466	—	—	74,904
Dividends on common stock ($2.56 per share)	—	—	—	—	—	(154,050)	—	(154,050)
Balance at December 31, 2023	**64,762**	**3,513**	**$ 648**	**$2,078,753**	**$ (97,926)**	**$ 811,495**	**$ (7,656)**	**$ 2,785,314**
Net income	—	—	—	—	—	224,111	—	224,111
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(4)	(4)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	504	504
Stock based compensation	49	—	—	4,672	(272)	—	—	4,400
Issuance of shares	—	(23)	—	708	804	—	—	1,512
Dividends on common stock ($2.60 per share)	—	—	—	—	—	(158,589)	—	(158,589)
Balance at December 31, 2024	**64,811**	**3,490**	**$ 648**	**$2,084,133**	**$ (97,394)**	**$ 877,017**	**$ (6,704)**	**$ 2,857,700**
Net income	—	—	—	—	—	181,092	—	181,092
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	18	18
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	173	173
Stock based compensation	84	17	1	6,933	(941)	—	—	5,993
Issuance of shares	—	(30)	—	869	832	—	—	1,701
Dividends on common stock ($2.64 per share)	—	—	—	—	—	(161,389)	—	(161,389)
Balance at December 31, 2025	**64,895**	**3,477**	**$ 649**	**$2,091,935**	**$ (97,503)**	**$ 896,720**	**$ (6,061)**	**$ 2,885,740**

See Notes to Consolidated Financial Statements

(1) Nature of Operations and Basis of Consolidation

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

The Consolidated Financial Statements for the periods included herein have been prepared by NorthWestern Energy Group (NorthWestern, we, or us), pursuant to the rules and regulations of the SEC. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The accompanying Consolidated Financial Statements include our accounts together with those of our wholly and majority-owned or controlled subsidiaries. All intercompany balances and transactions have been eliminated from the Consolidated Financial Statements. Events occurring subsequent to December 31, 2025, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

(2) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, unrecognized tax benefits, AROs, regulatory assets and liabilities, allowances for uncollectible accounts, our QF liability, environmental liabilities, unbilled revenues and actuarially determined benefit costs and liabilities. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

We recognize revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.9 million and $2.5 million at December 31, 2025 and December 31, 2024, respectively. Receivables include unbilled revenues of $98.8 million and $95.2 million at December 31, 2025 and December 31, 2024, respectively.

Inventories

Inventories are stated at the lower of average cost or net realizable value. Inventory consisted of the following (in thousands):

	December 31,	
	2025	2024
Materials and supplies	$ 110,740	$ 103,671
Storage gas and fuel	21,766	19,269
Total Inventories	$ 132,506	$ 122,940

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, *Regulated Operations*. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Statements of Income at that time. This would result in a charge to earnings and accumulated other comprehensive loss (AOCL), net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*. All derivatives are recognized in the Consolidated Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCL and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the underlying nature of the hedged items. As of December 31, 2025, the only derivative instruments we have qualify for the normal purchases and normal sales exception.

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 10 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, AFUDC, and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under finance lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. This rate averaged 7.2%, 7.0%, and 6.4% for Montana for 2025, 2024, and 2023, respectively. This rate averaged 6.9%, 6.9%, and 6.4% for South Dakota and Nebraska for 2025, 2024, and 2023, respectively. AFUDC capitalized totaled $14.7 million, $27.1 million, and $24.3 million for the years ended December 31, 2025, 2024, and 2023, respectively, for Montana, South Dakota, and Nebraska combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from 5 to 127 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.9% for each of 2025 and 2024, and 2.8% for 2023.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in noncurrent regulatory liabilities.

Pension and Postretirement Benefits

We have liabilities under defined benefit retirement plans and a postretirement plan that offers certain health care and life insurance benefits to eligible employees and their dependents. The costs of these plans are dependent upon numerous factors, assumptions and estimates, including determination of discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Accrued Expenses and other

Accrued expenses and other consisted of the following (in thousands):

	December 31,	
	2025	2024
Property taxes	$ 90,967	$ 81,716
Employee compensation, benefits, and withholdings	49,443	49,786
Interest	34,893	28,702
Customer advances	18,632	16,535
Other (none of which is individually significant)	78,438	77,860
Total Accrued Expenses	$ 272,373	$ 254,599

Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following (in thousands):

	December 31,	
	2025	2024
Customer advances	$ 138,255	$ 123,249
AROs	39,964	37,725
Environmental	22,961	20,350
Pension and other employee benefits	20,134	56,603
Future QF obligation, net	14,877	23,498
Other (none of which is individually significant)	47,344	54,619
Total Noncurrent Liabilities	$ 283,535	$ 316,044

Income Taxes

We follow the liability method in accounting for income taxes. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Consolidated Income Statements and provision for income taxes.

Under the Inflation Reduction Act of 2022 our production tax credits may be transferred to an unrelated entity. Our policy is to account for these transferable credits within income tax expense.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Cash (received) paid for:			
Federal income tax	$ 387	$ 525	$ (845)
State income tax[1]	(160)	(4,809)	18
Total Income taxes	$ 227	$ (4,284)	$ (827)
Production tax credits[2]	(12,293)	(6,867)	—
Interest	136,977	128,333	105,238
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	41,702	22,377	42,322

(1) For the year ended December 31, 2024, we received $4.8 million of cash from the state of Montana.
(2) Proceeds from production tax credits transferred are included in cash provided by operating activities within the Consolidated Statement of Cash Flows.

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

	December 31,		
	2025	2024	2023
Cash and cash equivalents	$ 8,781	$ 4,283	$ 9,164
Restricted cash	21,957	24,734	16,023
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 30,738	$ 29,017	$ 25,187

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounting Standards Issued

In December 2023, the Financial Accounting Standards Board issued Accounting Standards Update 2023-09, *Improvements to Income Tax Disclosures*, which expands public entities' income tax disclosures. The expanded disclosures require the disclosure of prescribed categories presented in the income tax rate reconciliation and additional disclosures on income tax expense and taxes paid, net of refunds received, for federal, state, and foreign jurisdictions. We adopted this standard for annual periods beginning after December 15, 2024, and interim periods beginning after December 15, 2025, as required, and used the retrospective method of adoption, with no material impact on our Consolidated Financial Statements.

At this time, we are not expecting the adoption of recently issued accounting standards to have a material impact to our financial condition, results of operations, and cash flows.

(3) Pending Merger with Black Hills Corporation

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

In connection with this pending merger, we have incurred merger-related costs. During the twelve months ended December 31, 2025, we have incurred $9.3 million of merger-related costs, which are included in our Administrative and general expenses.

Regulatory and Shareholder Approvals

Our pending merger with Black Hills was unanimously approved by our board of directors and Black Hills' board of directors. The completion of the Merger is subject to the satisfaction or waiver of certain conditions to closing, including (1) the approval of applicable transaction-related proposals by NorthWestern and Black Hills' shareholders in accordance with applicable law; (2) subject to certain conditions, the receipt of certain regulatory approvals, including expiration or termination of the applicable waiting period under the HSR Act and approval from the FERC, the MPSC, the NPSC, and the SDPUC, in each case on such terms and conditions that would not result in a material adverse effect on Bright Horizon Energy; (3) the absence of any court order or regulatory injunction prohibiting the completion of the Merger; (4) the authorization for listing of shares of Black Hills Common Stock to be issued in the Merger on a mutually agreed stock exchange; (5) subject to specified materiality standards, the accuracy of the representations and warranties of each party; (6) compliance by each party in all material respects with its covenants; (7) the absence of a material adverse effect on each party; and (8) receipt of each party of an opinion relating to the anticipated tax-free treatment of the Merger.

We have filed applications with the MPSC, NPSC, SDPUC, and FERC for approval of the Merger. Hearings with the MPSC, NPSC, and SDPUC are scheduled in the second quarter of 2026. In February 2026, the Form S-4, which contains joint proxy statement/prospectus for NorthWestern and Black Hills, was declared effective by the SEC. Meetings for NorthWestern and Black Hills shareholders to vote on the acquisition are scheduled for April 2, 2026. We expect to file an application for clearance under the HSR Act in the first quarter of 2026. We anticipate the transaction closing in the second half of 2026, subject to the satisfaction or waiver of certain closing conditions.

(4) Acquisition of Energy West Operations

In July 2024, NW Corp entered into an Asset Purchase Agreement with Hope Utilities to acquire its Energy West natural gas distribution system and operations serving approximately 33,000 customers located in Great Falls, Cut Bank, and West Yellowstone, Montana. In May 2025, the MPSC approved this acquisition and on July 1, 2025, NW Corp completed this acquisition for approximately $35.9 million in cash. Upon the completion of the acquisition, NW Corp transferred the utility operations to its two wholly-owned subsidiaries, NorthWestern Great Falls Gas LLC and NorthWestern Cut Bank Gas LLC.

The assets acquired and liabilities assumed were measured at estimated fair value in accordance with the accounting guidance under the Business Combinations Topic in the Financial Accounting Standards Board Accounting Standards Codification. These assets and liabilities are subject to rate-setting provisions that provide for revenues derived from costs, including a return on investment of assets less liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values.

The excess of the purchase price over the fair value of the assets acquired and liabilities assumed has been reflected as $10.0 million of goodwill within the Gas segment. Goodwill resulting from the acquisition is largely attributable to efficiency opportunities. The goodwill recognized in connection with the acquisition will be deductible for income tax purposes.

(5) Regulatory Matters

Montana Rate Review

In July 2024, we filed a Montana electric and natural gas rate review with the MPSC requesting an annual increase to electric and natural gas utility rates. In December 2025, the MPSC issued a final order approving the natural gas settlement agreement and partial electric settlement agreement. Among other things, the approved partial electric settlement agreement provides for the deferral and annual recovery of incremental operating costs related to wildfire mitigation and insurance expenses through the Wildfire Mitigation Balancing Account.

The details of this final order are set forth below:

Returns, Capital Structure & Revenue Increase Resulting From Final Order ($ in millions)

	Electric	Natural Gas
Return on Equity (ROE)	9.65 %	9.60 %
Equity Capital Structure	47.84 %	47.84 %
Base Rates	$ 105.5	$ 18.0
PCCAM[1][2]	(94.5)	n/a
Property Tax (tracker base adjustment)[1]	(1.8)	0.1
Total Revenue Increase Through Final Order	$ 9.2	$ 18.1

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(2) This PCCAM reduction of $94.5 million represents the reduction in revenue at the previously approved 2021 PCCAM base of $208.3 million using the 2023 Montana rate review test period loads.

The final order provides for an update to the PCCAM by adjusting the base costs from $208.3 million to $119.0 million. It also suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC. Within this final order, the MPSC disallowed a portion of the capital costs related to the construction of YCGS. As a result, in the fourth quarter of 2025 we recorded a $30.9 million non-cash charge for the regulatory disallowance within Operating and maintenance on the Consolidated Statements of Income and a corresponding reduction to Property, plant, and equipment, net on the Consolidated Balance Sheets. As of December 31, 2025, we have deferred $7.7 million of base rate revenues collected that will be refunded to customers.

In January 2026, we filed a Motion for Reconsideration (Motion) as it relates to this final order. Among other things, our Motion requests that the MPSC reconsider their prudence conclusions regarding the capital costs associated with the construction of YCGS and clarification as to the effective date of the PCCAM sharing mechanism suspension, 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 would be reflected in our 2026 results.

Nebraska Natural Gas Rate Review

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

Colstrip Acquisitions and Requests for Cost Recovery

In January 2023, and July 2024, we entered into definitive agreements with Avista and Puget, respectively, to acquire their respective interests in Colstrip Units 3 and 4 for $0 and completed these acquisitions on January 1, 2026. Accordingly, we are responsible for the associated operating costs beginning on January 1, 2026, which we will not collect through utility base rates, until requested in a future Montana rate review. Puget and Avista will remain responsible for their respective pre-closing share of environmental 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 would provide a near-term cost-recovery mechanism expected to largely offset 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.

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. 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. We expect this rate approval to be effective in the first quarter of 2026. If our request for rates effective January 1, 2026 is not approved, we could incur refund liability for contract revenues received during the unauthorized period.

(6) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on our assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2025	December 31, 2024
			(in thousands)	
Flow-through income taxes	14	Plant Lives	$ 632,322	$ 596,265
Supply costs		1 Year	47,438	11,441
Excess deferred income taxes	14	Plant Lives	42,534	45,620
Wildfire mitigation		Undetermined	29,433	17,368
Pension	16	See Note 16	26,942	62,096
State & local taxes & fees		1 Year	20,373	8,924
Employee related benefits	16	See Note 16	16,548	17,877
Deferred financing costs	13	See Note 13	16,089	17,754
Environmental clean-up	20	Undetermined	14,755	11,257
Other		Various	19,137	15,663
Total Regulatory Assets			**$ 865,571**	**$ 804,265**
Removal cost	8	Plant Lives	$ 561,690	$ 537,210
Excess deferred income taxes	14	Plant Lives	119,955	125,878
Supply costs		1 Year	17,765	20,933
Rates subject to refund	5	1 Year	7,660	—
Gas storage sales		14 years	5,784	6,205
State & local taxes & fees		1 Year	911	251
Employee related benefits	16	See Note 16	797	—
Other		Various	2,912	2,726
Total Regulatory Liabilities			**$ 717,474**	**$ 693,203**

Income Taxes

Flow-through income taxes primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, and removal costs that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. Excess deferred income tax assets and liabilities are recorded as a result of the Tax Cuts and Jobs Act and will be recovered or refunded in future rates. See Note 14 - Income Taxes for further discussion.

Supply Costs

The MPSC, SDPUC and NPSC have authorized the use of electric and natural gas supply cost trackers that enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we

have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on natural gas supply costs under collected, or apply interest to an over collection, of 6.7 percent in Montana; 6.8 percent and 6.9 percent for electric and natural gas, respectively, in South Dakota; and 7.1 percent for natural gas in Nebraska. For our Montana electric supply tracker, the PCCAM, the interest rate we earn on supply costs under collected, or the interest rate we apply to an over collection, is based on the monthly interest rate for three month commercial paper as published by the Federal Reserve.

Enhanced Wildfire Mitigation Plan

We have developed an Enhanced Wildfire Mitigation Plan addressing five key areas: situational awareness, operational practices, system preparedness, vegetation management, and public communications outreach. Because of ever-increasing wildfire risk, our plan includes greater focus on situational awareness to monitor changing environmental conditions, operational practices that are more reactive to changing conditions, increased frequency of patrol and repairs, and more robust system hardening programs that target higher risk segments in our transmission and distribution systems. The MPSC has approved the deferral of incremental operating costs related to this Enhanced Wildfire Mitigation Plan.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The MPSC allows recovery of pension costs on a cash funding basis. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension and postretirement benefit costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

State & Local Taxes & Fees

Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase, or refund the decrease, in rates, less the amount allocated to FERC jurisdictional customers and net of the related income tax benefit.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

Environmental Clean-Up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 20 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Removal Cost

The anticipated costs of removing assets upon retirement are collected from customers in advance of removal activity as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 8 - Asset Retirement Obligations, for further information regarding this item.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(7) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	December 31, 2025	December 31, 2024
	(in thousands)	
Electric Plant	$ 6,305,337	$ 6,034,159
Natural Gas Plant	1,794,216	1,615,228
Plant acquisition adjustment[1]	686,328	686,328
Common and Other Plant	281,454	277,623
Construction work in process	217,936	164,767
Total property, plant and equipment	9,285,271	8,778,105
Less accumulated depreciation	(2,159,330)	(2,019,142)
Less accumulated amortization	(387,092)	(360,688)
Net property, plant and equipment	$ 6,738,849	$ 6,398,275

(1) The plant acquisition adjustment balance above includes our Beethoven wind project acquired in 2015, our hydro generating assets acquired in 2014, and the inclusion of our interest in Colstrip Unit 4 in rate base in 2009. The acquisition adjustment is amortized on a straight-line basis over the estimated remaining useful life of each related asset in depreciation expense.

Net plant and equipment under finance lease were $1.0 million and $3.0 million as of December 31, 2025 and 2024, respectively, which is a long-term power supply contract with the owners of a natural gas fired peaking plant.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2025				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 157,919	$ 66,740	$ 53,609	$ 339,677
Accumulated depreciation	54,760	40,595	40,564	147,749
December 31, 2024				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 157,572	$ 65,426	$ 52,430	$ 330,888
Accumulated depreciation	49,573	39,025	39,887	137,153

On January 1, 2026, we acquired a 15 percent ownership interest in Colstrip Units 3 & 4 from Avista and a 25 percent ownership interest in Colstrip Units 3 & 4 from Puget, bringing our total ownership interest in Colstrip Units 3 & 4 to 55 percent. See Note 5 - Regulatory Matters for further discussion regarding these acquisitions.

(8) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the rate making process. We record regulatory assets and liabilities for differences in timing of asset retirement costs recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, U.S. Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our ARO (in thousands):

	December 31,		
	2025	2024	2023
Liability at January 1,	$ 41,052	$ 41,424	$ 40,894
Accretion expense	1,881	1,937	1,899
Liabilities incurred	371	—	—
Liabilities settled	(3,755)	(2,044)	(1,244)
Revisions to cash flows	1,828	(265)	(125)
Liability at December 31,	$ 41,377	$ 41,052	$ 41,424

During the twelve months ended December 31, 2025, our ARO liability decreased $3.8 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities and natural gas pipeline segments. Additionally, during the twelve months ended December 31, 2025, our ARO liability increased $2.2 million related to changes in both the timing and amount of retirement cost estimates and liabilities incurred.

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. The recorded amounts of costs collected from customers through depreciation rates are classified as a regulatory liability in recognition of the fact that we have collected these amounts that will be used in the future to fund asset retirement costs and do not represent legal retirement obligations. See Note 6 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2025 and 2024.

(9) Goodwill

We completed our annual goodwill impairment test as of April 1, 2025, and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash

flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

For the year ended December 31, 2025, goodwill increased $10.0 million. See Note 4 - Acquisition of Energy West Operations for additional information.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2025	2024
Electric	$ 243,558	$ 243,558
Natural gas	124,077	114,028
Total Goodwill	$ 367,635	$ 357,586

(10) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale (NPNS); cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Consolidated Financial Statements at December 31, 2025 and 2024. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements – standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

Interest Rate Swaps Designated as Cash Flow Hedges

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCL. We reclassify these gains from AOCL into interest expense during the periods in which the hedged interest payments occur. The following table shows the effect of these interest rate swaps previously terminated on the Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCL to Income	Amount Reclassified from AOCL into Income during the Year Ended December 31, 2025
Interest rate contracts	Interest Expense	$ 612

A pre-tax loss of approximately $11.6 million is remaining in AOCL as of December 31, 2025, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCL into interest expense during the next twelve months. These amounts relate to terminated swaps.

(11) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

Applicable accounting guidance establishes a hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and

- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, accounts payable, and short-term borrowings, the carrying amount of each such item approximates fair value. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. NPNS transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 10 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2025	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Restricted cash equivalents	$ 1,604	$ —	$ —	$ —	$ 1,604
Rabbi trust investments	19,669	—	—	—	19,669
Total	**$ 21,273**	**$ —**	**$ —**	**$ —**	**$ 21,273**
December 31, 2024					
Restricted cash equivalents	$ 1,076	$ —	$ —	$ —	$ 1,076
Rabbi trust investments	18,749	—	—	—	18,749
Total	**$ 19,825**	**$ —**	**$ —**	**$ —**	**$ 19,825**

Restricted cash equivalents represents amounts held in money market mutual funds. Rabbi trust investments represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2025		December 31, 2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 3,286,007	$ 3,007,897	$ 2,995,293	$ 2,645,779

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(12) Short-Term Borrowings and Credit Arrangements

Short-Term Borrowings

On April 12, 2024, NorthWestern Energy Group entered into a $100.0 million Term Loan Credit Agreement (Term Loan) with a maturity date of April 11, 2025. Borrowings may be made at a variable interest rate equal to the Secured Overnight Financing Rate plus an applicable margin as provided in the Term Loan. These proceeds were used to repay a portion of our outstanding revolving credit facility borrowings and for general corporate purposes. The Term Loan provides for prepayment of the principal and interest; however, amounts prepaid may not be reborrowed. The Term Loan requires us to maintain a consolidated indebtedness to total capitalization ratio of 65 percent or less. It also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and restricts certain affiliate transactions. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Term Loan; however a default on the Term Loan would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

On April 11, 2025, we amended our Term Loan to extend the maturity date from April 11, 2025 to April 10, 2026. On September 29, 2025, we amended our Term Loan to increase the total commitment to $150.0 million. As of December 31, 2025, we have borrowed $150.0 million under the Term Loan and the proceeds were used for general corporate purposes.

Credit Facility

On January 24, 2025, NW Corp amended its existing $400.0 million revolving credit facility (NW Corp Credit Facility) to increase the capacity to $425.0 million. The NW Corp Credit Facility has a maturity date of November 29, 2028 and this facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points. The NW Corp Credit Facility has uncommitted features that allow NW Corp to request one-year extensions to the maturity date and increase the size of the Amended Facility by an additional $75.0 million.

We have a $200.0 million unsecured revolver credit facility with base sublimits of $50.0 million for NorthWestern Energy Group and $150.0 million for NWE Public Service (the HoldCo and NWE Public Service Credit Facility). The HoldCo and NWE Public Service Credit Facility has a maturity date of November 29, 2028. The HoldCo and NWE Public Service Credit Facility has uncommitted features that allow both NorthWestern Energy Group and NWE Public Service to request one-year extensions to the maturity date and increase the size of the credit facility by an additional $50.0 million. The credit facility also gives us the flexibility to adjust the sublimits as needed, provided that NorthWestern Energy Group's base sublimit cannot exceed $100.0 million and NWE Public Service's sublimit cannot exceed $200.0 million. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points.

Commitment fees for the unsecured revolving lines of credit were $0.6 million and $0.7 million for the years ended December 31, 2025 and 2024.

The availability under the facilities in place for the years ended December 31 is shown in the following table (in millions):

	2025	2024
Unsecured revolving line of credit, expiring November 2028	**$ 625.0**	**$ 600.0**
Amounts outstanding at December 31:		
SOFR borrowings	404.0	413.0
Letters of credit	—	—
	404.0	**413.0**
Net availability as of December 31	**$ 221.0**	**$ 187.0**

Our credit facilities include covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facilities also contain covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. As it relates to the pending merger with Black Hills, we anticipate requesting a waiver to allow for the closing of the merger.

A default on the NW Corp Montana First Mortgage Bonds would trigger a cross default on the Amended Facility; however, a default on the Amended Facility would not trigger a default on the NW Corp Montana First Mortgage Bonds. A default on the NWE Public Service South Dakota First Mortgage Bonds would trigger a cross default on the NWE Public

Service sublimit of the HoldCo and NWE Public Service Credit Facility; however, a default on the HoldCo and NWE Public Service Credit Facility would not trigger a default on the NWE Public Service South Dakota First Mortgage Bonds.

(13) Long-Term Debt and Finance Leases

Long-term debt and finance leases consisted of the following (in thousands):

	Due	December 31, 2025	2024
Unsecured Debt:			
Unsecured Revolving Line of Credit	2028	404,000	413,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	—	64,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
South Dakota—5.55%	2029	33,000	33,000
South Dakota—3.21%	2030	50,000	50,000
South Dakota—5.57%	2033	31,000	31,000
South Dakota—5.42%	2033	30,000	30,000
South Dakota—5.75%	2034	7,000	7,000
South Dakota—5.49%	2035	100,000	—
South Dakota—4.26%	2040	70,000	70,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
Montana—5.01%	2025	—	161,000
Montana—3.11%	2025	—	75,000
Montana—3.99%	2028	35,000	35,000
Montana—5.073%	2030	500,000	—
Montana—3.21%	2030	100,000	100,000
Montana—5.56%	2031	175,000	175,000
Montana—5.57%	2033	239,000	239,000
Montana—5.71%	2039	55,000	55,000
Montana—4.15%	2042	60,000	60,000
Montana—4.85%	2043	15,000	15,000
Montana—4.176%	2044	450,000	450,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Montana—3.98%	2049	150,000	150,000
Montana—4.30%	2052	40,000	40,000
Pollution control obligations—			
Montana—3.88%	2028	144,660	144,660
Other Long Term Debt:			
Premium on Notes and Bonds and Debt Issuance Costs, Net		(12,653)	(12,367)
Total Long-Term Debt		$ 3,286,007	$ 2,995,293
Less current maturities (including associated debt issuance costs)		(104,967)	(299,950)
Total Long-Term Debt, Net of Current Maturities		$ 3,181,040	$ 2,695,343
Finance Leases:			
Total Finance Leases	2026	$ 1,865	$ 5,461
Less current maturities		(1,865)	(3,596)
Total Long-Term Finance Leases		$ —	$ 1,865

Secured Debt

First Mortgage Bonds

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under NWE Public Service's South Dakota indenture. These bonds are secured by substantially all of NWE Public Service's South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds are a series of general obligation bonds issued under NW Corp's Montana indenture. These bonds are secured by substantially all of NW Corp's Montana electric and natural gas assets.

On March 28, 2024, NW Corp issued and sold $175.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.56 percent maturing on March 28, 2031. These bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to redeem NW Corp's $100.0 million of Montana First Mortgage Bonds and for other general utility purposes. The bonds are secured by NW Corp's electric and natural gas assets associated with its Montana utility operations.

On March 28, 2024, NWE Public Service issued and sold $33.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.55 percent maturing on March 28, 2029, and $7.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.75 percent maturing on March 28, 2034. These bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933. Proceeds were used for general utility purposes. The bonds are secured by NWE Public Service's electric and natural gas assets associated with its South Dakota and Nebraska utility operations.

On March 21, 2025, and November 7, 2025, NW Corp issued and sold $400.0 million and $100.0 million, respectively, aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.07 percent maturing on March 21, 2030. These bonds were issued and sold to certain initial purchasers without being registered under the Securities Act of 1933, as amended (Securities Act), in reliance upon exemptions therefrom in compliance with Rule 144A under the Securities Act, or under Regulation S under the Securities Act for sales to non-U.S. persons. The proceeds from the March 2025 issuance were utilized to redeem NW Corp's $161.0 million of 5.01 percent Montana First Mortgage Bonds due May 1, 2025 and $75.0 million of 3.11 percent Montana First Mortgage Bonds due July 1, 2025, and for general utility purposes. The proceeds from the November 2025 issuance, which included $2.1 million of debt premium, were used for general utility purposes.

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

As of December 31, 2025, we were in compliance with our financial debt covenants.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and finance leases, during the next five years are $106.9 million in 2026, $583.7 million in 2028, $33.0 million in 2029, and $650.0 million in 2030.

(14) Income Taxes

Income tax expense (benefit) is comprised of the following (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Federal			
Current	$ (13,760)	$ (8,121)	$ 2,925
Deferred	21,494	(3,807)	2,929
Investment tax credits	1,146	1,970	(129)
State and other			
Current	37	(41)	(1,971)
Deferred	(2,444)	560	3,785
Income Tax Expense (Benefit)	$ 6,473	$ (9,439)	$ 7,539

Deferred income tax expense (benefit) is comprised of the following (in thousands):

	Year Ended December 31,		
	2025	2024	2023
Deferred tax expense excluding items below	$ 54,506	$ 54,950	$ 61,537
Adjustments to other noncurrent liabilities, regulatory assets, and liabilities	(48,328)	(65,596)	(54,732)
Tax benefit allocated to other comprehensive income	(206)	(293)	(91)
Adjustments to deferred income taxes for production tax credit cash transfer	13,078	7,692	—
Investment tax credits	1,146	1,970	(129)
Deferred Tax Expense (Benefit)	$ 20,196	$ (1,277)	$ 6,585

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

The table below reconciles our effective income tax rate to the federal statutory rate and summarizes the significant differences in income tax expense (benefit) based on the differences between our effective tax rate and the federal statutory rate (in thousands). Our income from continuing operations is primarily from domestic operations.

	Year Ended December 31,					
	2025		2024		2023	
	(in dollars)	(in percent)	(in dollars)	(in percent)	(in dollars)	(in percent)
Income before income taxes	$ 187,565		$ 214,672		$ 201,670	
Income tax calculated at federal statutory rate	39,389	21.0 %	45,081	21.0 %	42,350	21.0 %
State income tax, net of federal provision[1]	(1,500)	(0.8)	374	0.2	606	0.3
Tax Credits						
Production tax credits	(5,946)	(3.2)	(11,069)	(5.2)	(10,274)	(5.1)
Reduction to previously claimed alternative minimum tax credit	—	—	—	—	3,186	1.6
Other	656	0.4	695	0.3	(129)	(0.1)
Impact of utility ratemaking on income taxes						
Flow-through repairs deductions	(30,956)	(16.5)	(23,132)	(10.8)	(25,922)	(12.9)
Amortization of excess deferred income taxes	(3,169)	(1.7)	(2,930)	(1.4)	(2,184)	(1.1)
AFUDC, net	(1,349)	(0.7)	(2,570)	(1.2)	(2,122)	(1.1)
Plant and depreciation of flow through items	16,827	9.0	9,360	4.4	6,595	3.3
Gas repairs safe harbor method change	—	—	(6,994)	(3.3)	—	—
Changes in Unrecognized Tax Benefits						
Release of unrecognized tax benefits	(7,407)	(4.0)	(16,888)	(7.9)	(3,241)	(1.6)
Interest and penalties	(3,039)	(1.6)	(1,500)	(0.7)	1,500	0.7
Nontaxable and nondeductible items	2,878	1.5	367	0.2	354	0.2
Other						
Unregulated Tax Cuts and Jobs Act excess deferred income taxes	—	—	—	—	(3,385)	(1.7)
Other	89	0.1	(233)	0.0	205	0.2
	(32,916)	(17.5)	(54,520)	(25.4)	(34,811)	(17.3)
Income Tax Expense (Benefit) and Effective Tax Rate	$ 6,473	3.5 %	$ (9,439)	(4.4)%	$ 7,539	3.7 %

(1) For all years presented, the state of Montana comprises the majority of the domestic state income taxes, net of federal provisions.

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2025	2024
NOL carryforward	$ 114,031	$ 123,043
Production tax credit	89,511	97,695
Customer advances	36,406	32,455
Compensation accruals	13,033	12,717
Pension / postretirement benefits	—	9,078
Unbilled revenue	9,431	6,477
Environmental liability	6,154	5,415
Interest rate hedges	2,777	2,985
Reserves and accruals	1,482	2,252
Other	4,291	3,369
Deferred Tax Asset	**277,116**	**295,486**
Excess tax depreciation	(742,797)	(713,416)
Flow through depreciation	(143,300)	(132,944)
Goodwill amortization	(92,009)	(89,827)
Pension / postretirement benefits	(1,885)	—
Regulatory assets and other	(30,189)	(22,729)
Deferred Tax Liability	**(1,010,180)**	**(958,916)**
Deferred Tax Liability, net	**$ (733,064)**	**$ (663,430)**

As of December 31, 2025, our total federal NOL carryforward was approximately $452.2 million. Our federal NOL carryforward does not expire. Our state NOL carryforward as of December 31, 2025 was approximately $357.5 million. If unused, our state NOL carryforwards will expire in 2033. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

At December 31, 2025, our total production tax credit carryforward was approximately $89.5 million. If unused, our production tax credit carryforwards will expire as follows: $0.8 million in 2035, $10.9 million in 2036, $11.0 million in 2037, $10.9 million in 2038, $11.4 million in 2039, $13.1 million in 2040, $11.5 million in 2041, $13.2 million in 2042, $2.6 million in 2043, $2.3 million in 2044, and $1.8 million in 2045. We believe it is more likely than not that sufficient taxable income will be generated to utilize these production tax credit carryforwards.

Unrecognized Tax Benefits

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2025	2024	2023
Unrecognized Tax Benefits at January 1	$ 9,612	$ 28,074	$ 30,330
Gross increases - tax positions in prior period	—	—	—
Gross increases - tax positions in current period	—	—	—
Gross decreases - tax positions in current period	—	(1,574)	(2,256)
Lapse of statute of limitations	(9,612)	(16,888)	—
Unrecognized Tax Benefits at December 31	$ —	$ 9,612	$ 28,074

During the years ending December 31, 2025 and 2024, due to the expiration of the statute of limitations we decreased our unrecognized tax benefits by $9.6 million and $16.9 million, respectively. On April 14, 2023, the Internal Revenue Service (IRS) issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting for gas repairs expenditures. During the year ended December 31, 2023, we adopted this method and decreased our total unrecognized tax benefits by $0.5 million and recognized an income tax benefit of approximately $3.2 million for previously unrecognized tax benefits.

Our policy is to recognize interest and penalties related to unrecognized tax benefits in income tax expense. As of December 31, 2025, we have no accrual for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2024, we had $3.0 million accrued for the payment of interest and penalties.

Tax years 2022 and forward remain subject to examination by the IRS and state taxing authorities. During the first quarter of 2023 the IRS commenced and concluded a limited scope examination of our 2019 amended federal income tax return. This examination resulted in a reduction to our previously claimed alternative minimum tax credit refund that is reflected in the effective income tax rate reconciliation table above.

(15) Comprehensive Income (Loss)

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

	December 31,								
	2025			2024			2023		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Foreign currency translation adjustment	$ 18	$ —	$ 18	$ (4)	$ —	$ (4)	$ 2	$ —	$ 2
Reclassification of net income (loss) on derivative instruments	612	(160)	452	612	(160)	452	612	(160)	452
Postretirement medical liability adjustment	219	(46)	173	637	(133)	504	(331)	69	(262)
Other comprehensive income (loss)	$ 849	$ (206)	$ 643	$ 1,245	$ (293)	$ 952	$ 283	$ (91)	$ 192

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

	December 31,	
	2025	2024
Foreign currency translation	$ 1,451	$ 1,433
Derivative instruments designated as cash flow hedges	(8,469)	(8,921)
Postretirement medical plans	957	784
Accumulated other comprehensive loss	$ (6,061)	$ (6,704)

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

		December 31, 2025 Year Ended			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (8,921)	$ 784	$ 1,433	$ (6,704)
Other comprehensive income before reclassifications		—	—	18	18
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	173	—	173
Net current-period other comprehensive income (loss)		452	173	18	643
Ending Balance		$ (8,469)	$ 957	$ 1,451	$ (6,061)

		December 31, 2024 Year Ended			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)
Other comprehensive loss before reclassifications		—	—	(4)	(4)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	504	—	504
Net current-period other comprehensive income (loss)		452	504	(4)	952
Ending Balance		$ (8,921)	$ 784	$ 1,433	$ (6,704)

(16) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Energy SD/NE Plan, the pension plan for our Montana employees is referred to as the NorthWestern Energy MT Plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plans' funded status is recognized as an asset or liability in our Consolidated Financial Statements. See Note 6 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligations and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2025	2024	2025	2024
Change in benefit obligation:				
Obligation at beginning of period	$ 447,947	$ 473,988	$ 10,726	$ 13,708
Service cost	4,615	5,592	255	308
Interest cost	20,001	22,944	512	557
Actuarial gain	(11,063)	(28,499)	(1,590)	(2,514)
Settlements[1]	(221,423)	(848)	—	—
Benefits paid	(22,455)	(25,230)	(710)	(1,333)
Benefit Obligation at End of Period	$ 217,622	$ 447,947	$ 9,193	$ 10,726
Change in fair value of plan assets:				
Fair value of plan assets at beginning of period	$ 395,326	$ 402,671	$ 24,772	$ 22,309
Return on plan assets	38,191	9,411	3,649	3,177
Employer contributions	10,000	9,322	181	619
Settlements[1]	(221,423)	(848)	—	—
Benefits paid	(22,455)	(25,230)	(710)	(1,333)
Fair value of plan assets at end of period	$ 199,639	$ 395,326	$ 27,892	$ 24,772
Funded Status	$ (17,983)	$ (52,621)	$ 18,699	$ 14,046
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	8,801	9,467	21,216	16,943
Total Assets	8,801	9,467	21,216	16,943
Current liability	(11,500)	(10,000)	(1,143)	(1,310)
Noncurrent liability	(15,284)	(52,088)	(1,374)	(1,587)
Total Liabilities	(26,784)	(62,088)	(2,517)	(2,897)
Net amount recognized	$ (17,983)	$ (52,621)	$ 18,699	$ 14,046
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	—	—
Net actuarial (loss) gain	(295)	(31,835)	7,221	3,716
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	—	—
Net actuarial gain	—	—	1,268	1,228
Total	$ (295)	$ (31,835)	$ 8,489	$ 4,944

(1) In August 2025, we entered into a group annuity contract with an insurance company to provide for the payment of pension benefits to select NorthWestern Energy MT Pension Plan participants. We purchased the contract with $221.4 million of plan assets, representing 92 percent of the settled benefit obligation. The insurance company took over the payments of these benefits starting November 1, 2025. As a result of this transaction, during the twelve months ended December 31, 2025, we recorded a non-cash, non-operating settlement charge of $1.2 million. This charge is recorded within other income, net on the Consolidated Statements of Income. As discussed within Note 6 – Regulatory Assets and Liabilities, the MPSC allows recovery of pension costs on a cash funding basis. As such, this charge was deferred as a regulatory asset on the Consolidated Balance Sheets, with a corresponding decrease to operating and maintenance expense on the Consolidated Statements of Income.

The actuarial gain/loss is generally due to discount rate assumptions and actual asset returns compared with expected amounts. In the case of the NorthWestern Energy MT Pension Plan the actuarial gain/loss is mainly related to demographic changes as a result of the annuitization mentioned above. The total projected benefit obligation and fair value of plan assets for the NorthWestern Energy MT Pension Plan with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy MT Pension Plan	
	December 31,	
	2025	2024
Projected benefit obligation	$ 173.6	$ 404.8
Accumulated benefit obligation	173.6	404.8
Fair value of plan assets	146.8	342.7

As of December 31, 2025, the fair value of the NorthWestern Energy SD/NE Pension Plan assets exceeds the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2025	2024	2023	2025	2024	2023
Components of net periodic benefit cost						
Service cost	$ 4,615	$ 5,592	$ 5,646	$ 255	$ 308	$ 333
Interest cost	20,001	22,944	25,852	512	557	674
Expected return on plan assets	(18,882)	(25,325)	(25,932)	(1,418)	(1,280)	(1,096)
Amortization of prior service cost	—	—	—	—	—	116
Recognized actuarial loss (gain)	—	33	228	(275)	(73)	(672)
Settlement loss recognized[1]	1,168	—	4,395	—	—	—
Net Periodic Benefit Cost (Credit)	$ 6,902	$ 3,244	$ 10,189	$ (926)	$ (488)	$ (645)
Regulatory deferral of net periodic benefit cost[2]	3,490	4,850	(1,814)	—	—	—
Previously deferred costs recognized[2]	124	75	210	133	181	550
Net Periodic Benefit Cost (Credit) Recognized	$ 10,516	$ 8,169	$ 8,585	$ (793)	$ (307)	$ (95)

(1) Settlement losses are related to partial annuitizations of the NorthWestern Energy MT Pension Plan.
(2) Net periodic benefit costs for pension and postretirement benefit plans are recognized for financial reporting based on the authorization of each regulatory jurisdiction in which we operate. A portion of these costs are recorded in regulatory assets and recognized in the Consolidated Statements of Income as those costs are recovered through customer rates.

For the years ended December 31, 2025, 2024, and 2023, Service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other income, net on the Consolidated Statements of Income.

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2025 and 2024. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan

assets. During 2022, the plan's actuary conducted an experience study to review five years of plan experience and update these assumptions.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. During 2025, an increase in the discount rate of the MT Pension Plan due to the annuitization discussed above, partially offset by a decrease in the discount rate of SD/NE Pension Plan, resulted in an overall decrease to our projected benefit obligation of approximately $0.1 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we increased our long term rates of return on asset assumptions for the NorthWestern Energy MT Pension Plan and the NorthWestern Energy SD/NE Pension Plan to 6.3 percent and 4.96 percent, respectively, for 2026.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2025	2024	2023	2025	2024	2023
Discount rate	5.20-5.65 %	5.50-5.60 %	4.95-5.00 %	4.85-5.05 %	5.30-5.45 %	4.85-4.90 %
Expected rate of return on assets	4.58-6.17	5.15-6.65	4.83-6.44	5.80	5.84	5.62
Long-term rate of increase in compensation levels (non-union)	4.00	4.00	4.00	4.00	4.00	4.00
Long-term rate of increase in compensation levels (union)	4.00	4.00	4.00	4.00	4.00	4.00
Interest crediting rate	3.3-6.0	3.3-6.0	3.30-6.00	N/A	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5 percent fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, Prudent Man Rule of the Employee Retirement Income Security Act of 1974 and liability-based considerations. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- Pension plan portfolio risk is described by volatility in the funded status of the Plans;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan’s aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the pension plans overall funded status, (such assets will be described as Liability Hedging Fixed Income assets);
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Private real estate and broad global opportunistic fixed income asset classes can provide diversification to both equity and liability hedging fixed income investments and a moderate allocation to each can potentially improve the expected risk-adjusted return for the NorthWestern Energy MT Pension Plan investments over full market cycles;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk) and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocations established, within an allowable range of plus or minus 3 - 8.5 percent (depending on investment category), is as follows:

	NorthWestern Energy MT Pension		NorthWestern Energy SD/NE Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2025	2024	2025	2024	2025	2024
Fixed income securities	45.0 %	45.0 %	90.0 %	90.0 %	40.0 %	40.0 %
Opportunistic fixed income	11.0	11.0	3.0	3.0	—	—
Global equities	38.5	38.5	7.0	7.0	60.0	60.0
Private real estate	5.5	5.5	—	—	—	—

The actual allocation by plan is as follows:

	NorthWestern Energy MT Pension		NorthWestern Energy SD/NE Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2025	2024	2025	2024	2025	2024
Cash and cash equivalents[1]	4.7 %	— %	0.9 %	0.8 %	0.4 %	0.3 %
Fixed income securities[2]	37.9	43.7	89.0	89.4	30.8	32.2
Opportunistic fixed income	9.1	11.1	3.0	2.9	—	—
Global equities[2]	33.3	39.0	7.1	6.9	68.8	67.5
Private real estate[2]	15.0	6.2	—	—	—	—
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

(1) Includes a substantial required cash allocation for the NorthWestern Energy MT Pension Plan related to a new overlay strategy designed to mitigate interest rate risk. Cash and cash equivalents, for purposes of this strategy, would be considered fixed income securities as it relates to target investment allocations.

(2) While some of the actual asset allocations above differ from established target allocations as of December 31, 2025, the plan Investment Manager has 60 days to initiate action to rebalance portfolios, when allocations fall out of acceptable ranges. While target allocations are the goal, both plan liquidity needs and investment liquidity terms (particularly as they pertain to the NorthWestern Energy MT Pension Plan annuitization mentioned above) may cause temporary imbalances to occur.

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Both plan liquidity needs and investment liquidity terms may affect the timing of rebalancing. Investment policy guidelines allow for a transition to targets over time. Debt securities consist of U.S. and international instruments including emerging markets and high yield instruments, as well as government, corporate, asset backed and mortgage backed securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Equity, real estate and fixed income portfolios may be comprised of both active and passive management strategies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks. We also invest in global equities with exposure to developing and emerging markets. Equity investments may also be diversified across investment styles such as growth and value. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes. Real estate investments will consist of global equity or debt interests in tangible property consisting of land, buildings, and other improvements in commercial and residential sectors.

The following tables set forth, both by level within the fair value hierarchy and by net asset value (NAV) as a practical expedient, the assets (in thousands) that were accounted for on a recurring basis:

	December 31, 2025					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value[1]	Total Investments Measured at NAV (Common Collective Trusts)	Total Investments
Pension Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 7,418	$ 7,418
Fixed income securities	—	13,542	—	13,542	88,975	102,517
Opportunistic fixed income	—	—	—	—	14,965	14,965
Global equities	—	—	—	—	52,660	52,660
Private real estate	—	—	—	—	22,079	22,079
Total investments	$ —	$ 13,542	$ —	$ 13,542	$ 186,097	$ 199,639
Other Postretirement Benefits Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 103	$ 103
Fixed income securities	5,940	—	—	5,940	2,653	8,593
Global equities	3,808	—	—	3,808	15,388	19,196
Total investments	$ 9,748	$ —	$ —	$ 9,748	$ 18,144	$ 27,892

	December 31, 2024					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value[1]	Total Investments Measured at NAV (Common Collective Trusts)	Total Investments
Pension Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 502	$ 502
Fixed income securities	—	—	—	—	196,588	196,588
Opportunistic fixed income	—	—	—	—	39,727	39,727
Global equities	—	—	—	—	137,321	137,321
Private real estate	—	—	—	—	21,188	21,188
Total investments	$ —	$ —	$ —	$ —	$ 395,326	$ 395,326
Other Postretirement Benefits Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 72	$ 72
Fixed income securities	5,504	—	—	5,504	2,475	7,979
Global equities	3,093	—	—	3,093	13,628	16,721
Total investments	$ 8,597	$ —	$ —	$ 8,597	$ 16,175	$ 24,772

(1) See Note 11 - Fair Value Measurements for further information on fair value measurement inputs and methods.

The following are descriptions of the methods and assumptions used to value investments held by pension and other postretirement trusts.

- Common/Collective Trusts: The majority of our plan assets are held by common collective trusts (CCTs). In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class, be invested in a diversified manner and have a minimum of three years of verified investment performance experience or have a portfolio manager with a minimum of three years of verified investment experience in a similar investment strategy. The fund must have management and/or oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's NAV per share by the number of units or shares owned at the valuation date. NAV per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted

closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The direct holding of NorthWestern Energy Group stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted.

- Registered Investment Companies: Investments in mutual funds, categorized as global equities above, sponsored by a registered investment company are valued based on exchange listed prices. Where the value is a quoted price in an active market, the investment is classified within Level 1 of the fair value hierarchy.
- Fixed Income Securities: Certain fixed income securities are valued at the closing price reported in the active market in which the security is traded. Other fixed income securities are valued based on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar securities, the bonds are valued for the trustee by a pricing vendor on the basis of bid or mid evaluations in accordance to the region's market convention, using factors which include but are not limited to market quotes, yields, maturities and the bond's terms and conditions. Pricing vendors use proprietary methods to arrive at the evaluated price, which represents the price a dealer would pay for the security.
- Derivative Financial Instruments: Futures contracts that are publicly traded in active markets are valued at closing prices as of the last business day of the year. Fixed income futures and options are marked to market daily.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. Additional funding relief was passed in the American Rescue Plan Act of 2021, providing for longer amortization and interest rate smoothing, which we elected to use. We expect to continue to make contributions to the pension plans in 2026 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension costs for 2025, 2024 and 2023 were based on actual contributions to the NorthWestern Energy MT Pension Plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2025	2024	2023
NorthWestern Energy MT Pension Plan	$ 10,000	$ 8,122	$ 8,000
NorthWestern Energy SD/NE Pension Plan	—	1,200	1,200
	$ 10,000	$ 9,322	$ 9,200

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2026	15,334	1,652
2027	9,627	1,050
2028	10,799	977
2029	11,400	868
2030	12,186	894
2031-2035	71,848	3,641

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to the plan. We also contribute various percentages of employees' gross compensation to the plan. Company contributions for the years ended December 31, 2025, 2024 and 2023 totaled $15.5 million, $14.7 million, and $13.2 million, respectively.

(17) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. As of December 31, 2025, there were 411,984 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to two years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Performance Unit Awards

Performance unit awards are granted annually under the ECP. These awards contain service-, market-, and performance-based components. The service-based component of these awards, representing 30 percent of the award, vest at the end of the three-year performance period as long as the individual has remained employed with us over that term. The performance goals are independent of each other and equally weighted at 35 percent of the award, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return relative to a peer group. These awards vest at the end of the three-year performance period if we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued under the market- and performance-based components will vary from 0 percent to 200 percent of the target award, depending on actual company performance relative to the performance goals.

Fair value is determined for each component of the performance unit awards. The fair value of the service-based component is estimated based upon the closing market price of our common stock as of the grant date less the present value of expected dividends. The fair value of the performance-based component is estimated based upon the closing market price of our common stock as of the grant date less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the market-based component is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2025	2024
Risk-free interest rate	4.37 %	4.38 %
Expected life, in years	3	3
Expected volatility	15.3% to 30.2%	12.5% to 29.0%
Dividend yield	4.9 %	5.6 %

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2025, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	231,926	$ 46.07
Granted	138,658	48.91
Vested	(85,928)	54.41
Forfeited	(2,435)	46.26
Remaining nonvested grants	282,221	$ 44.92

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. Awards granted before 2022 are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Awards granted in 2022 no longer contain this performance measure, instead these awards will vest after five full calendar years if the employee remains employed during that service period. No retirement/retention restricted shares were granted during the year ended December 31, 2025. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the grant date less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2025, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	50,796	$ 45.40
Granted	—	—
Vested	(12,916)	44.57
Forfeited	—	—
Remaining nonvested grants	37,880	$ 45.68

We recognized total stock-based compensation expense of $5.7 million, $3.4 million, and $3.6 million for the years ended December 31, 2025, 2024, and 2023, respectively, and related income tax benefit of $1.5 million, $0.7 million, and $1.0 million for the years ended December 31, 2025, 2024, and 2023, respectively. As of December 31, 2025, we had $6.8 million of unrecognized compensation cost related to the nonvested portion of our outstanding awards. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $4.7 million, $3.1 million, and $4.4 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(18) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of the common stock, 2,856,957 shares are reserved for the incentive plan awards. For further detail of grants under this plan see Note 17 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 16,591 and 5,809 during the years ended December 31, 2025 and 2024, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Dividend Restrictions

Due to our holding company structure, liquidity necessary to pay dividends to holders of our common stock is generally provided by dividend distributions from our utility subsidiaries. Under various state regulatory agreements, debt agreements and the Federal Power Act, our utility subsidiaries have restrictions, including minimum equity ratios, that limit the amount of dividend distributions that can be made.

Pursuant to the MPSC regulatory agreement with NW Corp, if NW Corp's secured credit ratings are above BBB- for S&P Global Ratings and Baa3 for Moody's Investor Services, NW Corp may declare or pay dividends as long as NW Corp's common equity ratio is 40 percent or above. If NW Corp's secured credit ratings are BBB- for S&P Global Ratings or Baa3 for Moody's Investor Services, NW Corp may declare or pay dividends as long as NW Corp's common equity ratio is 43 percent or above. If NW Corp's secured credit ratings fall below BBB- with S&P Global Ratings or Baa3 with Moody's Investor Services, NW Corp may not declare or pay dividends to NorthWestern Energy Group.

NorthWestern Energy Group, NW Corp, and NWE Public Service's ability to pay dividends is also limited by the terms of various debt agreements, pursuant to which, NorthWestern Energy Group, NW Corp, and NWE Public Service are required to maintain a debt to capitalization ratio of no more than 0.65 to 1.00. Further, the declaration of dividends is at the discretion of our Board of Directors and is not guaranteed.

As of December 31, 2025, approximately $615.9 million and $264.4 million of NW Corp and NWE Public Service unrestricted net assets, respectively, were available for the payment of dividends to NorthWestern Energy Group under our most restrictive dividend restriction.

(19) 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:

	December 31,		
	2025	2024	2023
Basic computation	61,381,328	61,293,052	60,321,481
Dilutive effect of			
Performance and restricted share awards[1]	160,090	81,153	36,312
Diluted computation	61,541,418	61,374,205	60,357,793

(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 December 31, 2025, there were no shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations.

(20) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. These contracts require us to purchase minimum amounts of energy at prices ranging from $124 to $130 per MWH through 2029. As of December 31, 2025, our estimated gross contractual obligation related to these contracts was approximately $168.6 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $152.8 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Fuel, purchased power and direct transmission expense and Electric revenues in our Consolidated Statements of Income. The present value of the remaining liability is recorded in Other noncurrent liabilities in our Consolidated Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2025	2024
Beginning QF liability	$ 23,498	$ 28,670
Settlements	(10,206)	(7,606)
Interest expense	1,585	2,434
Ending QF liability	$ 14,877	$ 23,498

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2026	$ 55,393	$ 46,274	$ 9,119
2027	56,665	46,668	9,997
2028	42,400	41,664	736
2029	14,134	18,231	(4,097)
Total[(1)]	$ 168,592	$ 152,837	$ 15,755

(1) This net unrecoverable amount represents the undiscounted difference between the total gross obligations and recoverable amounts. The ending QF liability in the table above represents the present value of this net unrecoverable amount.

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. Costs incurred under these contracts are included in Fuel, purchased power and direct transmission expense in the Consolidated Statements of Income and were approximately $276.8 million, $290.1 million and $340.0 million for the years ended December 31, 2025, 2024, and 2023, respectively. As of December 31, 2025, our commitments under these contracts were $424.5 million in 2026, $343.7 million in 2027, $340.1 million in 2028, $341.5 million in 2029, $316.7 million in 2030, and $2.1 billion thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $18.1 million between 2026 and 2040. These commitments are not reflected in our Consolidated Financial Statements.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us or for which we are responsible, is estimated to range between $21.2 million to $34.7 million. As of December 31, 2025, we had a reserve of approximately $26.6 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

The following summarizes the change in our environmental liability (in thousands):

	December 31,		
	2025	2024	2023
Liability at January 1,	$ 23,729	$ 25,286	$ 26,367
Additions	2,638	—	—
Deductions	(2,043)	(2,262)	(2,520)
Charged to costs and expense	2,289	705	1,439
Liability at December 31,	$ 26,613	$ 23,729	$ 25,286

We are permitted to recover the remediation costs related to certain environmental liabilities within rates. Over time, as costs become determinable, we may seek authorization to recover additional costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery for all remediation costs, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

Manufactured Gas Plants - Approximately $21.3 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Agriculture and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2025, the reserve for remediation costs at this site was approximately $7.8 million, and we estimate that approximately $2.7 million of this amount will be incurred through 2030. The SDPUC permits the recovery of these costs within rates.

Nebraska - We own sites in North Platte, Kearney, and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

Montana - We own or have responsibility for sites in Butte, Missoula, Helena, and Great Falls Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the MDEQ voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and field work was completed in 2022. We submitted a Remedial Investigation Report (RI Report) summarizing the work completed to MDEQ in March 2022 and received initial comments back from DEQ in August 2025, which require revisions and additional information which are expected to be completed in 2026. Additional field work may be required by DEQ and will commence after the RI Report is finalized by MDEQ.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership, we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party has assumed the lead role at the site and has expressed its intention to submit a voluntary remediation plan for the Missoula site to MDEQ. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

In connection with the acquisition of the Energy West operations we recognized an additional $2.6 million reserve for remediation costs associated with a site in Great Falls, Montana that was identified during the acquisition. The MPSC has previously approved the recovery of costs related to this site, and as such, the costs associated with this reserve have been deferred as a regulatory asset on the Consolidated Balance Sheets. If approval to recover costs from retail customers is subsequently denied, our Asset Purchase Agreement with Hope Utilities includes provisions that allow us to seek recovery from them.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of GHG including, most significantly, carbon dioxide (CO_2) and methane emissions from natural gas. These actions include legislative proposals, Executive, Congressional and EPA actions at the federal level, state level activity, investor activism and private party litigation relating to emissions. Coal-fired plants have come under particular scrutiny due to their level of emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

EPA Rules **-** Congress has not passed any federal climate change legislation regarding GHG emissions from coal fired plants, and we cannot predict the timing or form of any potential legislation. Section 111(d) of the Clean Air Act (CAA) confers authority on EPA and the states to regulate emissions, including GHGs, from existing stationary sources. On April 25, 2024, the EPA released final rules related to GHG emission standards (GHG Rules) for existing coal-fired facilities and new coal and natural gas-fired facilities as well as final rules strengthening the MATS requirements (MATS Rules). Compliance with the rules would require expensive upgrades at Colstrip Units 3 and 4 with proposed compliance dates that may not be achievable and / or require technology that is unproven, resulting in significant impacts to costs of the facilities. The final MATS and GHG Rules require compliance as early as 2027 and 2032, respectively.

On June 11, 2025, the EPA issued a Notice of Proposed Rulemaking containing two proposals to reform GHG regulations. If either the lead or alternative proposal is adopted, our additional material compliance costs would be eliminated. On June 11, 2025, the EPA also issued a Notice of Proposed Rulemaking to rescind the 2024 MATS Rule, which if enacted, would restore the original 2012 MATS standards. There is no mandated timeline for final action on the rules.

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

Regional Haze Rules - In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

The states of Montana, North Dakota and South Dakota have developed and submitted to the EPA, for its approval, their respective State Implementation Plans (SIP) for Regional Haze compliance. While these states, among others, did not meet the EPA’s July 31, 2021, submission deadline, they were all submitted in 2022. The Montana SIP as drafted and submitted to EPA does not call for additional controls for our interest in Colstrip Unit 4. The draft North Dakota SIP does not require any additional controls at the Coyote generating facility. Similarly, the draft South Dakota SIP does not require any additional controls at the Big Stone generating facility. Until these SIPs are finalized and approved by EPA, the potential remains that installation of additional emissions controls might be required at these facilities.

Jointly Owned Plants - We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been or may be issued or proposed.

Other - We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

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

(21) Revenue from Contracts with Customers

Accounting Policy

Our revenues are primarily from tariff based sales. We provide gas and/or electricity to customers under these tariffs without a defined contractual term (at-will). As the revenue from these arrangements is equivalent to the electricity or gas supplied and billed in that period (including estimated billings), there will not be a shift in the timing or pattern of revenue recognition for such sales. We have also completed the evaluation of our other revenue streams, including those tied to longer term contractual commitments. These revenue streams have performance obligations that are satisfied at a point in time, and do not have a shift in the timing or pattern of revenue recognition.

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Nature of Goods and Services

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

Electric Segment - Our regulated electric utility business primarily provides generation, transmission, and distribution services to our customers in our Montana and South Dakota jurisdictions. We recognize revenue when electricity is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to our customers in our Montana, South Dakota, and Nebraska jurisdictions. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Disaggregation of Revenue

The following tables disaggregate our revenue for the twelve months ended by major source and customer class (in thousands):

December 31, 2025	Electric	Natural Gas	Total
Montana	406,643	120,830	527,473
South Dakota	77,894	28,948	106,842
Nebraska	—	25,733	25,733
Residential	**484,537**	**175,511**	**660,048**
Montana	408,530	68,722	477,252
South Dakota	120,108	21,574	141,682
Nebraska	—	13,784	13,784
Commercial	**528,638**	**104,080**	**632,718**
Industrial	43,128	2,439	45,567
Lighting, governmental, irrigation, and interdepartmental	34,510	1,350	35,860
Total Retail Revenues	**1,090,813**	**283,380**	**1,374,193**
Regulatory Amortization	58,265	(305)	57,960
Transmission	111,024	—	111,024
Transportation, wholesale and other	9,854	57,528	67,382
Total Revenues	**$ 1,269,956**	**$ 340,603**	**$ 1,610,559**

December 31, 2024	Electric	Natural Gas	Total
Montana	398,790	110,215	509,005
South Dakota	70,012	26,884	96,896
Nebraska	—	21,205	21,205
Residential	**468,802**	**158,304**	**627,106**
Montana	408,977	59,925	468,902
South Dakota	111,813	18,069	129,882
Nebraska	—	11,432	11,432
Commercial	**520,790**	**89,426**	**610,216**
Industrial	46,637	1,041	47,678
Lighting, governmental, irrigation, and interdepartmental	32,811	1,352	34,163
Total Retail Revenues	**1,069,040**	**250,123**	**1,319,163**
Regulatory Amortization	24,908	19,017	43,925
Transmission	97,052	—	97,052
Transportation, wholesale and other	9,701	44,057	53,758
Total Revenues	**$ 1,200,701**	**$ 313,197**	**$ 1,513,898**

December 31, 2023	Electric	Natural Gas	Total
Montana	408,341	136,097	544,438
South Dakota	67,888	36,638	104,526
Nebraska	—	35,539	35,539
Residential	**476,229**	**208,274**	**684,503**
Montana	431,357	73,721	505,078
South Dakota	103,194	25,869	129,063
Nebraska	—	22,114	22,114
Commercial	**534,551**	**121,704**	**656,255**
Industrial	45,958	1,392	47,350
Lighting, governmental, irrigation, and interdepartmental	32,756	1,681	34,437
Total Retail Revenues	**1,089,494**	**333,051**	**1,422,545**
Regulatory Amortization	(105,608)	(25,012)	(130,620)
Transmission	78,436	—	78,436
Transportation, wholesale and other	6,511	45,271	51,782
Total Revenues	**$ 1,068,833**	**$ 353,310**	**$ 1,422,143**

(22) Segment and Related Information

Our reportable segments are engaged in the electric and gas utility businesses. Our Electric segment includes the aggregated operating segment results of the regulated electric utility operations of Montana and South Dakota. Our Gas segment includes the aggregated operating segment results of the regulated gas utility operations of Montana, South Dakota, and Nebraska.

Our CODM, who is our Chief Executive Officer, uses segment net income to evaluate if our operating segments are earning their authorized rate of return and in the annual budget and forecasting process. Our CODM uses segment net income to determine how to allocate capital resources between our operating segments and when to allocate the resources necessary to file for rate reviews. The accounting policies of the operating segments are the same as those described within Note 2 – Significant Accounting Policies. Segment asset and capital expenditure information is not provided for our reportable segments. As an integrated electric and gas utility, we operate significant assets that are not dedicated to a specific reportable segment.

Financial data for the business segments for the twelve months ended are as follows (in thousands):

December 31, 2025	Electric	Gas	Total
Operating revenues	$ 1,269,956	$ 340,603	$ 1,610,559
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	306,569	103,186	409,755
Operating, general, and administrative	331,477	101,257	432,734
Property and other taxes	140,937	41,204	182,141
Depreciation and depletion	208,565	40,961	249,526
Interest expense, net	(113,525)	(30,271)	(143,796)
Other income, net	7,574	3,702	11,276
Income tax (expense) benefit	(16,029)	(1,087)	(17,116)
Segment net income	$ 160,428	$ 26,339	$ 186,767
Reconciliation to consolidated net income			
Other, net[1]			(5,675)
Consolidated net income			$ 181,092

December 31, 2024	Electric	Gas	Total
Operating revenues	$ 1,200,701	$ 313,197	$ 1,513,898
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	329,578	104,238	433,816
Operating, general, and administrative	270,145	92,211	362,356
Property and other taxes	126,470	37,386	163,856
Depreciation and depletion	189,987	37,648	227,635
Interest expense, net	(99,250)	(27,740)	(126,990)
Other income, net	18,082	5,803	23,885
Income tax (expense) benefit	(20,892)	7,963	(12,929)
Segment net income	$ 182,461	$ 27,740	$ 210,201
Reconciliation to consolidated net income			
Other, net[1]			13,910
Consolidated net income			$ 224,111

December 31, 2023	Electric	Gas	Total
Operating revenues	$ 1,068,833	$ 353,310	$ 1,422,143
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	262,755	157,507	420,262
Operating, general, and administrative	249,549	87,153	336,702
Property and other taxes	120,289	34,323	154,612
Depreciation and depletion	174,071	36,403	210,474
Interest expense, net	(84,089)	(15,719)	(99,808)
Other income, net	11,580	3,344	14,924
Income tax (expense) benefit	(14,196)	4,627	(9,569)
Segment net income	$ 175,464	$ 30,176	$ 205,640
Reconciliation to consolidated net income			
Other, net[1]			(11,509)
Consolidated net income			$ 194,131

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

(23) Fourth Quarter Financial Data (Unaudited)

Our fourth quarter financial information has not been audited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Amounts presented are in thousands, except per share data:

	Three Months Ended December 31,	
	2025	2024
Operating revenues	$ 414,265	$ 373,466
Operating income	60,024	91,696
Net income	$ 44,691	$ 80,552
Average common shares outstanding	61,409	61,315
Income per average common share:		
Basic	$ 0.73	$ 1.32
Diluted	$ 0.72	$ 1.31

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF NORTHWESTERN ENERGY GROUP

NORTHWESTERN ENERGY GROUP

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

(PARENT COMPANY ONLY)

(in thousands)

	Year Ended December 31,		
	2025	2024	2023[1]
Operating Expenses:			
Administrative and general	$ 10,511	$ 1,134	$ 231
Property and other taxes	159	—	—
Total Operating Expenses	10,670	1,134	231
Operating Loss	10,670	1,134	231
Interest expense	(6,556)	(4,683)	—
Earnings from investments in subsidiaries, net of tax	186,712	207,650	83,142
Other income, net	785	212	230
Income before income taxes	170,271	202,045	83,141
Income tax benefit	10,821	22,066	—
Net Income	181,092	224,111	83,141
Other comprehensive income from subsidiaries, net of tax	643	952	365
Comprehensive Income	$ 181,735	$ 225,063	$ 83,506

(1) NorthWestern Energy Group did not have operational activity until October 2, 2023. Refer to Note 1 - Basis of Presentation to the Condensed Financial Statements for further information.

See Notes to Condensed Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED BALANCE SHEET

(PARENT COMPANY ONLY)

(in thousands)

	As of December 31,	
	2025	**2024**
ASSETS:		
Current Assets:		
Cash and cash equivalents	$ 739	$ 726
Accounts receivable	9,936	1,689
Total current assets	**10,675**	**2,415**
Investments in subsidiaries	3,020,267	2,996,648
Deferred tax assets	11,612	9,578
Other noncurrent assets	4,996	4,613
Total Assets	**$ 3,047,550**	**$ 3,013,254**
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Short-term borrowings	$ 150,000	$ 100,000
Accounts payable	—	2,742
Accrued expenses and other	2,332	21
Total current liabilities	**152,332**	**102,763**
Long-term debt	926	36,901
Deferred tax liabilities	3,556	3,083
Other noncurrent liabilities	4,996	12,807
Total Liabilities	**161,810**	**155,554**
Total Shareholders' Equity	**2,885,740**	**2,857,700**
Total Liabilities and Shareholders' Equity	**$ 3,047,550**	**$ 3,013,254**

See Notes to Condensed Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED STATEMENTS OF CASH FLOWS

(PARENT COMPANY ONLY)

(in thousands)

	Year Ended December 31,		
	2025	2024	2023[1]
OPERATING ACTIVITIES:			
Net Income	$ 181,092	$ 224,111	$ 83,141
Adjustments to reconcile net income to cash used in operations:			
Equity in earnings from subsidiaries, net of tax	(186,712)	(207,650)	(83,142)
Cash dividends received from subsidiaries	181,385	91,183	39,042
Amortization of debt issuance costs	52	25	—
Stock-based compensation costs	51	50	—
Deferred income taxes	(8,464)	(18,588)	—
Changes in assets and liabilities			
Accounts receivable	(8,247)	(1,483)	(207)
Accounts payable	(2,742)	684	—
Accrued expenses	2,310	(219)	—
Other noncurrent assets and liabilities	(1,292)	(2,272)	—
Cash Provided by Operating Activities	157,433	85,841	38,834
INVESTING ACTIVITIES:			
Contributions to subsidiaries	(10,714)	(64,777)	—
Return of capital from subsidiaries	—	—	—
Cash Used in Investing Activities	(10,714)	(64,777)	—
FINANCING ACTIVITIES:			
Dividends on common stock	(161,389)	(158,589)	(39,002)
Issuances of short-term borrowings	50,000	100,000	—
Line of credit (repayments) borrowings, net	(36,000)	37,000	—
Treasury stock activity	709	1,192	351
Financing costs	(26)	—	(124)
Cash Used in Financing Activities	(146,706)	(20,397)	(38,775)
Net Increase in Cash and Cash Equivalents	13	667	59
Cash, Cash Equivalents and Restricted Cash, beginning of period	726	59	—
Cash and Cash Equivalents end of period	$ 739	$ 726	$ 59

(1) NorthWestern Energy Group did not have operational activity until October 2, 2023. Refer to Note 1 - Basis of Presentation to the Condensed Financial Statements for further information.

See Notes to Condensed Financial Statements

NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) Basis of Presentation

NorthWestern Energy Group is an energy services holding company that conducts substantially all of its business operations through its subsidiaries, NW Corp and NWE Public Service. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These financial statements, in which NorthWestern Energy Groups' subsidiary has been included using the equity method of accounting, should be read in conjunction with the Consolidated Financial Statements and notes thereto of NorthWestern Energy Group contained elsewhere within this Form 10-K.

There were $181.4 million, $91.2 million, and $39.0 million of cash dividends paid to NorthWestern Energy Group from wholly-owned subsidiaries for the year ending December 31, 2025, December 31, 2024, and December 31, 2023, respectively.

Holding Company Reorganization

On October 2, 2023, NW Corp and NorthWestern Energy Group completed a merger transaction pursuant to which NorthWestern Energy Group became the holding company parent of NW Corp. NW Corp became a wholly-owned subsidiary of NorthWestern Energy Group. The transaction was effected pursuant to a merger pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the shareholders of the constituent corporation. As a result of the reorganization, NorthWestern Energy Group became the successor issuer to NW Corp pursuant to Rule 12g-3(a) of the Securities Exchange Act of 1934, and as a result, NorthWestern Energy Group's common stock was deemed registered under Section 12(b) of the Securities Exchange act of 1934.

(2) Short-Term Borrowings and Credit Arrangements

For information concerning NorthWestern Energy Groups' short-term borrowings and credit arrangements, see Note 12 - Short-Term Borrowings and Credit Arrangements to the Consolidated Financial Statements of NorthWestern Energy Group included within this Form 10-K.

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