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, 2023

OR

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

For the transition period from to

Commission File Number: 000-56598

NORTHWESTERN ENERGY GROUP, INC.

(Exact name of registrant as specified in its charter)

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

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

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 $3,404,946,692 computed using the last sales price of $56.76 per share of the registrant's common stock on June 30, 2023, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 9, 2024, 61,256,549 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 2024 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

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 and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

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

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

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption “Risk Factors” which is part of the disclosure included in Part 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 facility.

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 facility located near Colstrip, Montana, of which we have a 30 percent ownership of Unit 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, a 150 MW natural gas fired 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 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.

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

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 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.

Request for Proposals (RFP) - The resource solicitation process that is run by a third party and evaluates the least cost resources that address key risks and needs identified by the IRP.

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, which is currently under construction and expected to be online no later than the end of the third quarter 2024.

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

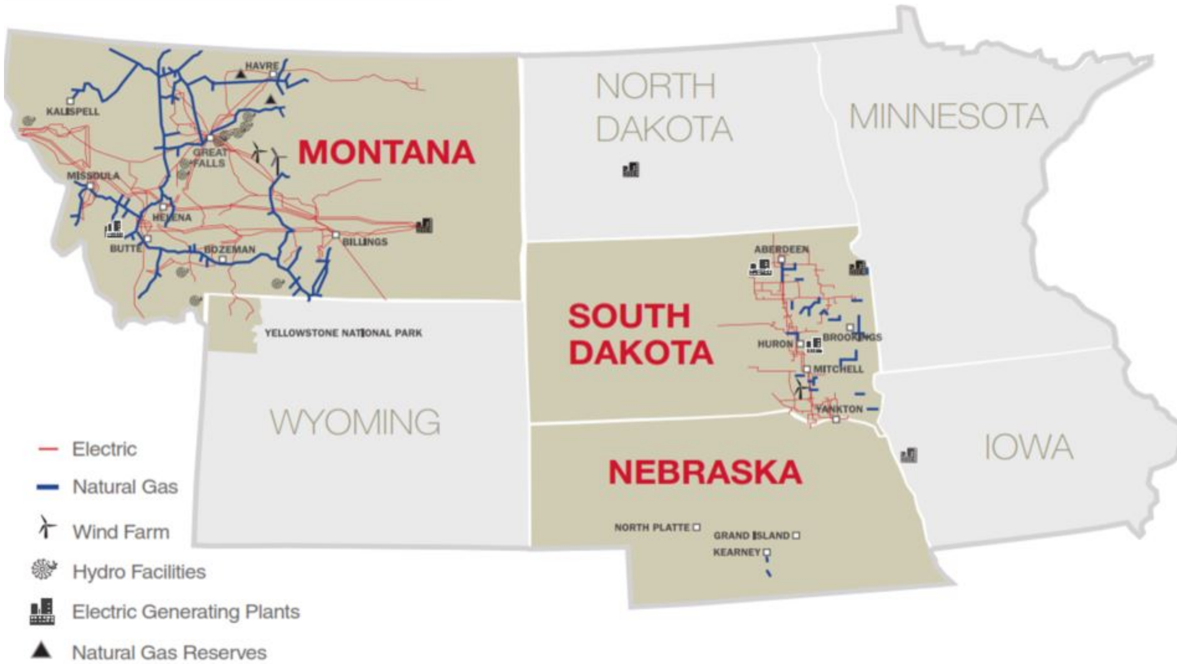
NorthWestern Energy Group, doing business as NorthWestern Energy, provides essential energy infrastructure and valuable services that enrich lives and empower communities while serving as long-term partners to our customers and communities. We work to deliver safe, reliable, and innovative energy solutions 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 775,300 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. We have provided service in South Dakota and Nebraska since 1923 and in Montana since 2002.

On October 2, 2023, NW Corp created a new public holding company, NorthWestern Energy Group, by initiating a holding company reorganization (the Reorganization), pursuant to an internal merger transaction through which NorthWestern Energy Group became the successor issuer to NW Corp under the Securities Exchange Act of 1934, as amended. On January 1, 2024, NorthWestern Energy Group, NW Corp, and NW Corp's wholly owned subsidiary, NWE Public Service, completed the final phase of its Reorganization by contributing the assets and liabilities of its South Dakota and Nebraska regulated utilities to NWE Public Service and distributing its equity interests in NWE Public Service and certain other unregulated subsidiaries to NorthWestern Energy Group. As a result of these transactions, (1) NW Corp owns and operates the Montana regulated utility; (2) NWE Public Service owns and operates the Nebraska and South Dakota regulated utilities; and (3) NW Corp and NWE Public Service are each direct, wholly owned subsidiaries of NorthWestern Energy Group.

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.

SERVICE TERRITORY



Environmental, Social and Governance

We are focused on meeting current energy infrastructure and service needs at a reasonable and fair cost for today's customers while ensuring the ability to meet the needs of tomorrow's customers. "Sustainability" requires meeting economic, societal, and environmental objectives. As a provider of essential infrastructure and service, a sustainable enterprise is vital to our customers and communities, as well as to our investors and employees.

Over the past 100 years, we have maintained our commitment to provide customers with reliable and affordable electric and natural gas services while also being good stewards of the environment. 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.

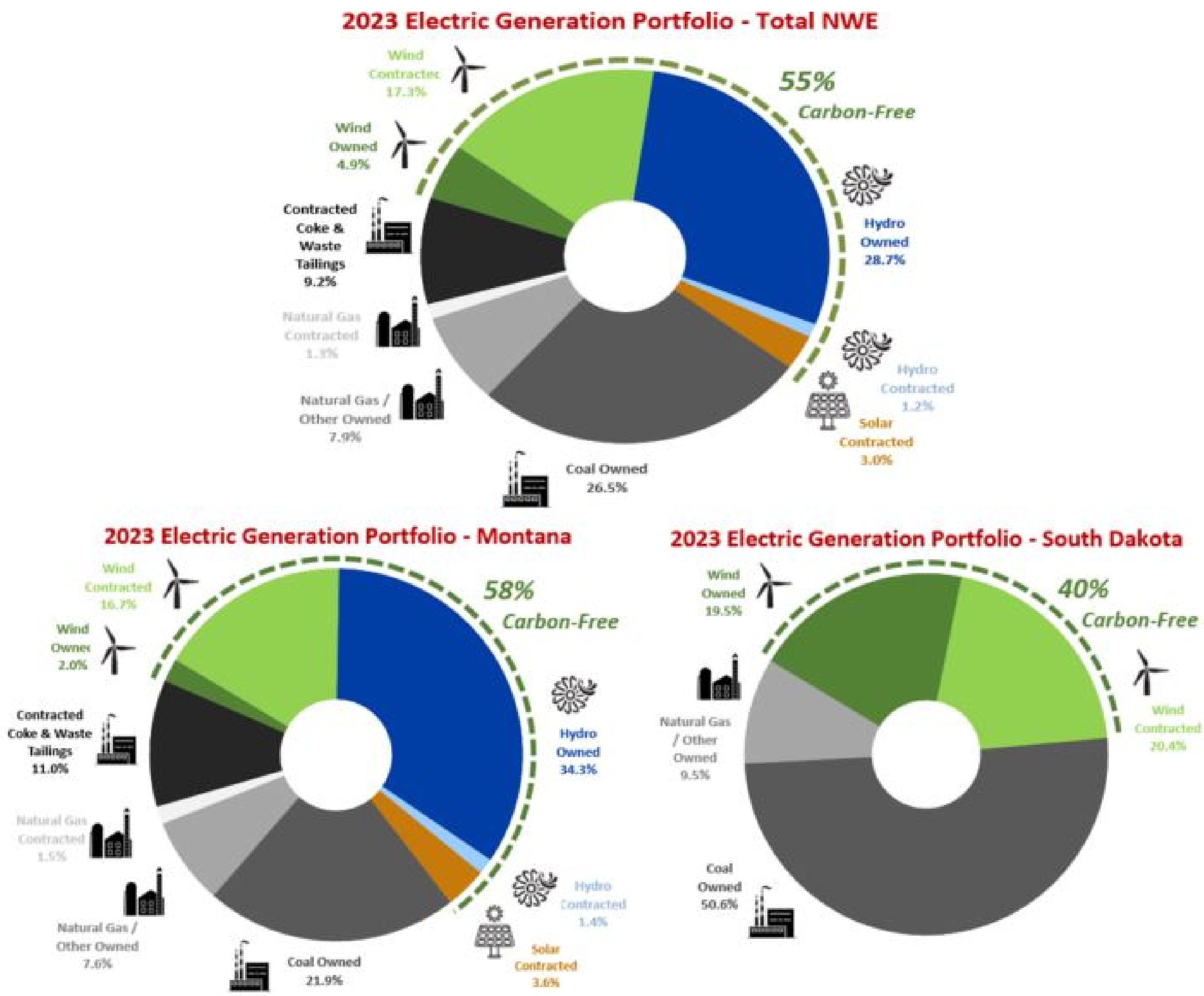
We currently own a mix of clean and carbon-free energy resources balanced with traditional energy sources that are necessary for us to deliver affordable and reliable electricity to our customers 24/7. In 2023, approximately 55 percent of our retail needs originated from carbon-free resources, compared to approximately 40 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 2022. We do not receive all of the related Renewable Energy Credits (RECs) from our contracted electric supply resources and periodically sell RECs produced by our own carbon-free energy 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 gap between resources and customer demand.

We are a fully regulated provider of critical infrastructure and essential services. Therefore, our success in meeting our obligations to our customers and the communities we serve depends on public policy. We believe that policy makers in the states we serve are committed to reliable, adequate, and affordable service, and a strong customer focus. We support policies that enable investment in critical infrastructure and responsible stewardship.

We believe that technological advancements, along with decreasing costs of carbon-free generation and the regionalization of intermittent generation, will significantly contribute to our goal of Net-Zero carbon emissions by 2050. The pace of transition to Net-Zero will depend on the timing of technological advancements, costs, and retirement of our existing coal fleet.

In South Dakota and Montana, we develop an IRP every two and three years, respectively. These IRPs, which are presented to our state regulatory commissions, identify resource needs, known and expected risks, as well as key variables to be used in evaluating resources. We then undertake a transparent resource solicitation process, run by a third party, to evaluate the least cost resources that address key risks and needs identified by the IRP. All generation types have the opportunity to participate in our RFP. Therefore, the specific resources that will be acquired to meet future needs are dependent upon our current and future IRPs and the RFP process, in conjunction with the actions of our regulators during the regulatory process.

For a more detailed description of our environmental, social, governance and sustainability activities, please visit our company website at https://www.northwesternenergy.com. 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.



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

Contracted energy from coke and waste tailings as well as a majority of the contracted wind, hydro and solar are federally mandated Qualifying Facilities, as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA).

MONTANA ELECTRIC OPERATIONS

Our regulated electric utility business in Montana, which is 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 2023, we delivered electricity to approximately 405,500 customers in 221 communities and their surrounding rural areas, 13 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2023, by category, residential, commercial, industrial, and other sales accounted for approximately 45%, 47%, 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	3,931
Total Miles of Electric Transmission Lines	**6,600**
Electric Distribution Lines	
Miles of overhead line	13,271
Miles of underground line	5,403
Total Miles of Electric Distribution Lines	**18,674**
Total Transmission and Distribution Substations	**395**

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 1,992 MWs on February 22, 2023. Our control area average demand for 2023 was approximately 1,376 MWs per hour, with total energy delivered of more than 12.05 million MWHs.

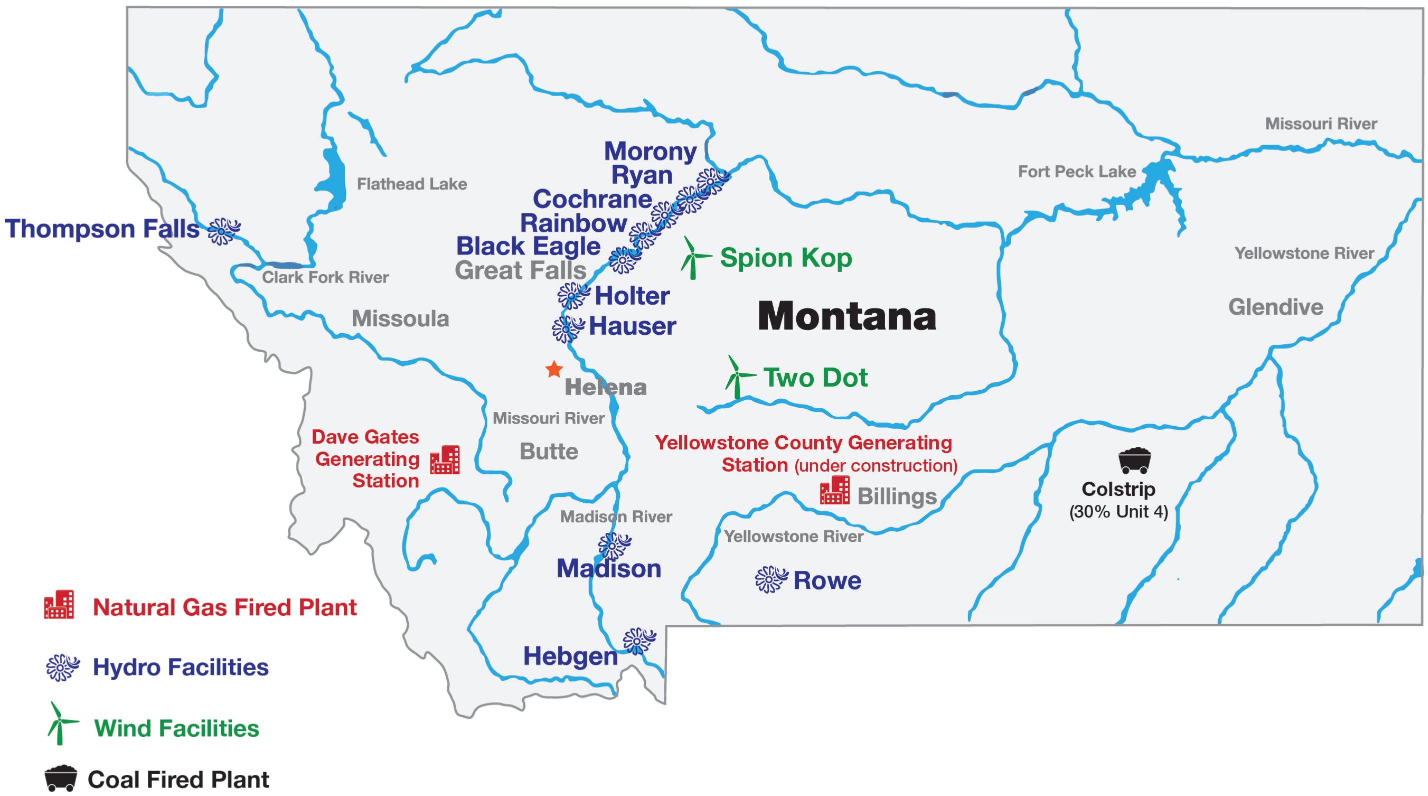
Our transmission system is directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; WAPA; and Montana Alberta Tie. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, 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 requirements average approximately 750 MWs, with a peak load of approximately 1,300 MWs, and are supplied by owned and contracted resources and market purchases with multiple counterparties.

Owned generation resources supplied approximately 71 percent of our retail load requirements for 2023. We expect that approximately 85 percent of our retail obligations will be met by owned generation resources in 2024, reflecting the addition of YCGS which is expected to be online no later than the end of the third quarter 2024. In addition, we have contracts with QFs totaling 549 MWs of nameplate capacity, including 87 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 20 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 2024. Load requirements during peak demand in excess of our owned and long-term contracted resources will be satisfied with market purchases.

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	62
Hauser	1911	Missouri	2040	21
Holter	1918	Missouri	2040	53
Madison	1906	Madison	2040	12
Morony	1930	Missouri	2040	49
Rowe(1)	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	64
Ryan	1915	Missouri	2040	72
Thompson Falls	1915/1995	Clark Fork	2025	94
Total(2)				**464**

(1) Formerly known as the Mystic Lake Dam.
(2) The Hebgen facility (0 MW net capacity) is excluded from the figures above. These are run-of-river dams except for Mystic, which is storage generation.

Other Facilities	Fuel Source	Ownership Interest	Owned MW
Colstrip Unit 4, located near Colstrip in southeastern Montana	Sub-bituminous coal	30%	222
DGGS, located near Anaconda, Montana	Natural Gas & Liquid Fuel	100%	150
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

Colstrip Unit 4 provides base-load supply and is operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. 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. Colstrip Unit 4 is supplied with fuel from adjacent coal reserves under a coal supply agreement in effect through 2025. See *Item 1A Risk Factors* "Regulatory, Legislative and Legal Risks" for further discussion regarding the service life of generation facilities.

Resource Planning

Resource planning is an important function necessary to meet our customers' future energy needs and is used to guide resource acquisition activities. We filed our latest resource plan with the MPSC in April of 2023. The filing showed a capacity adequate resource portfolio in the near term that included an online date of the Yellowstone County Generating Station in 2024 and the acquisition of an additional 222 MW of capacity in Colstrip in 2026. However, it also showed projected generation capacity deficits in future years.

In addition to our responsibility to meet peak demand, national NERC reliability standards increased the need for us to have greater dispatchable generation capacity available and be capable of increasing or decreasing output to address intermittent generation such as wind and solar. Our generation portfolio is a balanced mix of energy and capacity resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet our obligation to serve retail customers 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 64,800 in 116 communities in South Dakota. In 2023, 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	1,267
Total Miles of Electric Transmission Lines	**1,310**
Electric Distribution Lines	
Miles of overhead line	1,634
Miles of underground line	731
Total Miles of Electric Distribution Lines	**2,365**
Total Transmission and Distribution Substations	**124**

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.

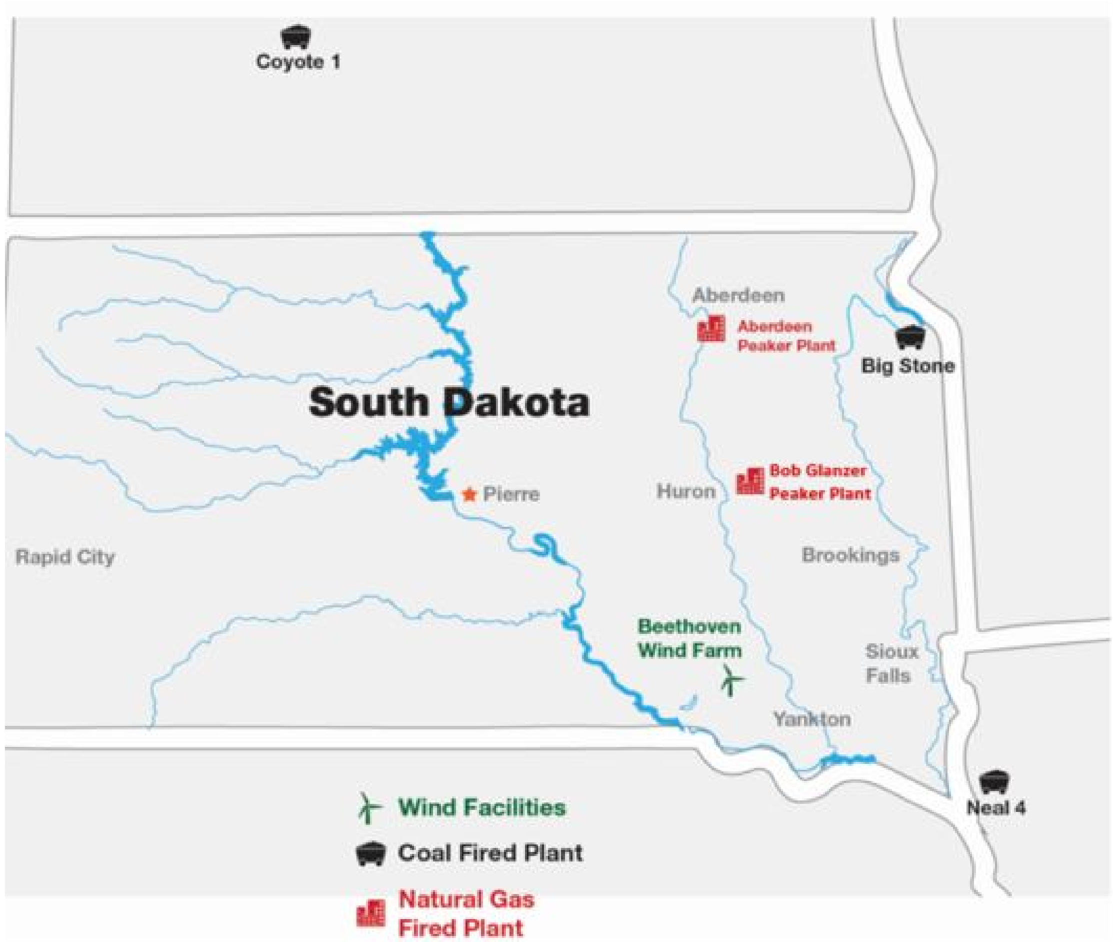
We are a transmission-owning member in the SPP, with our transmission facilities residing in zone 19 of the SPP footprint. Each year, we review all new or modified transmission assets and transfer functional control of assets that qualify under the SPP Tariff to the SPP. This annual update goes into 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. 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 200 MWs, with a peak load of approximately 340 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 138 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 Units No. 1 and 2, located near Aberdeen, South Dakota	Natural gas & Liquid Fuel	100.0%	80
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%	57
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%	17
Total			**446**

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 have a resource plan that includes estimates of customer usage and programs to provide for the economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis.

We submitted a plan to the SDPUC in September of 2022 that provided for the modernization of our generating fleet. That plan focused on improving reliability and flexibility. Following the competitive solicitation processes, we completed construction of the 58 MW BGGS in the summer of 2022. The BGGS plant includes flexible reciprocating internal combustion engines at a brownfield site near Huron, South Dakota. We plan to replace aging generation resources in the Aberdeen, South Dakota area by 2025 for a total projected cost of $70.0 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 2023, we distributed natural gas to approximately 212,100 customers in 118 Montana communities over a system that consists of approximately 5,200 miles of underground distribution pipelines. We also serve several smaller distribution companies that provide service to approximately 34,000 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 48 Bcf during the year ended December 31, 2023.

Miles of Natural Gas Transmission	**2,235**
Miles of Natural Gas Distribution	**5,155**
City Gate Stations	**133**

We have connections in Montana with four major, unaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, and Spur Energy. Twelve compressor sites provide more than 48,600 horsepower on the transmission line and an additional 15,100 horsepower at our storage fields, capable of moving more than 364,000 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 two 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, 2023, were approximately 22.5 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2023, were approximately 6.8 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 protected from potential price spikes in the market. As of December 31, 2023, these owned reserves totaled approximately 31.5 Bcf and are estimated to provide approximately 2.8 Bcf in 2024, or approximately 12 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 49,800 customers in 80 South Dakota communities and approximately 43,100 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 five gas-marketing firms and one large end-user account. We delivered approximately 31.1 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 2023.

Miles of Natural Gas Transmission	**55**
Miles of Natural Gas Distribution - South Dakota	**1,747**
Miles of Natural Gas Distribution - Nebraska	**826**

Our South Dakota natural gas supply requirements for the year ended December 31, 2023, 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, 2023, were approximately 4.5 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. The terms of the franchises vary by community. Our Montana franchises typically have a fixed 10-year term and continue for additional 10-year terms unless and until canceled, with 5 years notice. 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. During the next five years, twelve of our Montana franchises could expire by action taken by the franchises' city or town, which account for approximately 83,947 or 40 percent of our Montana natural gas customers. Three of our South Dakota franchises and one franchise in Nebraska, which account for approximately 19,111 or 20 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 3 - 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, 2023:

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]	November 2023	$2,565.5	$2,874.8	6.72%	9.65%	48.02%
Montana - Colstrip Unit 4	November 2023	276.9	257.7	8.25%	10.00%	50.00%
Montana natural gas delivery and production[2]	November 2023	582.8	744.1	6.67%	9.55%	48.02%
Total Montana		$3,425.2	$3,876.6			
South Dakota electric[3] [4]	January 2024	$791.8	$810.3	6.81%	n/a	n/a
South Dakota natural gas[3]	December 2011	65.9	95.8	7.80%	n/a	n/a
Total South Dakota		$857.7	$906.1			
Nebraska natural gas[3]	December 2007	$24.3	$50.1	8.49%	10.40%	n/a
		$4,307.2	$4,832.8			

(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) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.
(4) On June 15, 2023, we filed a South Dakota electric rate review filing (2022 test year) with the SDPUC. See Note 3 - Regulatory Matters for additional discussion of this rate review filing.

MPSC Regulation

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. 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 January 2024, we received approval of a Phase in Rate Plan Rider, which may allow recovery of capital investments without filing a general electric rate review. SDPUC approval of the plan and associated project cost recovery are required.

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.

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 under the terms of those licenses and FERC regulations. In connection with the relicensing of these generating facilities, applicable law permits the FERC to issue a new license to the existing licensee, to a new licensee, or alternatively allows the U.S. government to take over the facility. If the existing licensee is not relicensed, it is compensated for its net investment in the facility, not to exceed the fair value of the property taken, plus reasonable severance damages to other property affected by the lack of relicensing.

***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. 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.

To this end, the Biden Administration set ambitious goals to address climate change, including the goal of a carbon free power sector by 2035 and net zero carbon emissions by 2050. Executive Orders issued by the Biden Administration included initiatives and directives intended to reduce GHG emissions, address climate change and decarbonize the energy sector. These Executive Orders established climate considerations as key components of United States foreign policy and national security, established a White House Office of Domestic Climate policy as well as a National Climate Task Force, called for agency heads to identify any fossil fuel subsidies provided by their agencies and to take steps to ensure that federal funding is not directly subsidizing fossil fuels, and directed agencies to immediately review all regulations proposed or finalized by the Trump Administration that conflict with the Biden Administration’s objectives and to take action to rescind or revise those rules.

President Biden's Infrastructure Investment and Jobs Act and Inflation Reduction Act of 2022 contain significant climate initiatives. These initiatives present opportunities for federal grants and tax incentives intended to hasten the future economy-wide deployment of various GHG reducing technologies and approaches.

Implementation of these initiatives and directives has 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.

Estimated capital expenditures for environmental control facilities in 2024 and 2025 are not expected to be material. For more information on environmental regulations and contingencies and related capital expenditures, see Note 18 - Commitments and Contingencies, to the Consolidated Financial Statements.

CORPORATE INFORMATION AND WEBSITE

We were incorporated in Delaware on May 30, 2023. On October 2, 2023, pursuant to an internal merger transaction, NorthWestern Energy Group became the successor issuer to NW Corp (incorporated in Delaware in November 1923) under the Securities Exchange Act of 1934, as amended. 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 by offering competitive salaries and benefits, providing a safe working environment, valuing diversity, fostering inclusion and encouraging a healthful work–life balance. Our success comes when employees feel empowered to take initiative, voice their opinions, and build on their experiences within our company and our communities.

As of December 31, 2023, we had 1,573 employees. Of these, 1,269 employees were in Montana and 304 were in South Dakota or Nebraska. Of our Montana employees, 462, or 36 percent, were covered by seven collective bargaining agreements involving five unions, which were renegotiated in 2022. Each of the Montana collective bargaining agreements will expire in 2026. Of our South Dakota and Nebraska employees, 171, or 56 percent, are covered by a collective bargaining agreement renegotiated in 2021 that expire in 2025. We consider our relations with employees to be good.

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.

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 2023 and 2022, the compensation for our Chief Executive Officer (CEO) was approximately 22 and 26 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 2023, approximately 75 percent of the targeted compensation of our CEO and about 56 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 23 to 1.

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 2023, with no corrective action required.

Diversity

We believe a diverse and inclusive workforce adds value and helps us succeed in an ever-changing environment. By embracing diversity and fostering inclusion, we aim to enable each employee, executive, and director to contribute fully to the company. We believe diversity is important because varied perspectives expand our ability to bring unique professional experiences to our business. Diversity in the workforce will be considered when relevant to hiring, promotions, work assignments, or other decisions related to the terms and conditions of employment. Our workforce reflects the relative diversity of our available talent in the communities we serve. Our employment data is tested annually by a third party as part of our Affirmative Action plan development to identify any needed corrective placement goals that are required. This testing determined that there is no current need to establish corrective placement goals in our plan.

We continue to maintain a diverse workforce, with an executive team that is 50% female and a board of directors that is 40% female and has two ethnically diverse members (20%).

Health and Safety

As stewards of critical infrastructure, providers of energy service, and members of the communities we serve, our priority is the health and safety of our employees and customers. Safety and health are considered and integrated into all work activities. We monitor several different key areas relating to safety philosophies and policies. These key metrics include the recordable incident rate (number of work-related injuries per 100 employees for a one-year period) and lost time incident rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). During the years ended December 31, 2023 and 2022, our recordable incident rates were 1.34 and 1.57 and lost time incident rates were 0.45 and 0.59 on a company wide basis. Our five-year average safety record for the year ended December 31, 2023 was better than our industry peer group's five-year average.

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 NorthWestern Energy Public Service Corporation since January 1, 2024, and of NorthWestern Corporation since January 2023; formerly President and Chief Operating Officer of NorthWestern Corporation since February 2021 and Chief Financial Officer from December 2003 to February 2021.	61
Crystal D. Lail	Vice President and Chief Financial Officer of NorthWestern Energy Group, Inc., since October 2, 2023, and of NorthWestern Energy Public Service Corporation since January 1, 2024, and of NorthWestern Corporation since February 2021; formerly Vice President and Chief Accounting Officer of NorthWestern Corporation since April 2020; and Vice President and Controller from October 2015 to April 2020.	45
Shannon M. Heim	Vice President - General Counsel and Federal Government Affairs of NorthWestern Energy Group, Inc., since October 2, 2023, and of NorthWestern Energy Public Service Corporation since January 1, 2024, and of NorthWestern Corporation since January 2023; formerly Director, Regulatory Corporate Counsel of NorthWestern Corporation since June 2020; and formerly Equity Shareholder at the law firm of Moss & Barnett, P.A. from 2017 to 2020.	51
Bleau J. Lafave	Vice President - Asset Management & Business Development of NorthWestern Corporation since June 2023 and of NorthWestern Energy Public Service Corporation since January 1, 2024; formerly Director of Long-Term Resources of NorthWestern Corporation since 2003.	53
Bobbi L. Schroeppel	Vice President - Customer Care, Communications and Human Resources of NorthWestern Corporation since May 2009 and of NorthWestern Energy Public Service Corporation since January 1, 2024.	55
Cyndee S. Fang	Vice President - Regulatory Affairs of NorthWestern Corporation since January 2023 and of NorthWestern Energy Public Service Corporation since January 1, 2024; formerly Director - Regulatory Affairs of NorthWestern Corporation since March 2021; prior to joining the Company, she was Origination & Portfolio Design Manager from December 2020 to March 2021, Manager of Energy Research & Analysis from August 2018 to December 2020, and Manager of Customer Pricing from June 2017 to August 2018, in each case, for San Diego Gas and Electric Company, an electric and gas utility.	54
Jason C. Merkel	Vice President - Distribution of NorthWestern Corporation since September 2022 and of NorthWestern Energy Public Service Corporation since January 1, 2024; formerly General Manager - Operations and Construction of NorthWestern Corporation since 2007.	56
Jeanne M. Vold	Vice President - Technology of NorthWestern Corporation since February 2021 and of NorthWestern Energy Public Service Corporation since January 1, 2024; formerly Business Technology Officer of NorthWestern Corporation since 2012.	57
John D. Hines	Vice President - Supply and Montana Government Affairs of NorthWestern Corporation since January 2018 and of NorthWestern Energy Public Service Corporation since January 1, 2024; formerly Vice President - Supply of NorthWestern Corporation since May 2011.	65
Michael R. Cashell	Vice President - Transmission of NorthWestern Corporation since May 2011 and of NorthWestern Energy Public Service Corporation since January 1, 2024.	61

(1) As of February 9, 2024.

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.

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 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. 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, including legislative, judicial, and regulatory responses to climate change, 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, climate change, 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. We believe that we are in compliance with environmental regulatory requirements.

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. No rules are currently in effect that require us to reduce our GHG emissions. However, laws and regulations to which we must adhere change, and the Biden Administration's agenda includes a significant shift in environmental and energy policy, focusing on reducing GHG emissions and addressing climate change issues.

Together, these actions reflect climate change issues and GHG emissions as central areas of focus for domestic and international regulations, orders and policies. In addition, a parallel focus on reducing GHG emissions is reflected in legislation introduced in Congress. These initiatives could lead to new and revised energy and environmental laws and regulations, including tax reforms relating to energy and environmental issues. Any such changes, as well as any enforcement actions or judicial decisions regarding those laws and regulations, could result in 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.

Although previous attempts by the EPA to regulate GHG emissions from coal-fired plants have not succeeded, if GHG and/or methane regulations are implemented, compliance with carbon dioxide (CO_2) emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

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. See discussion related to our Yellowstone County Generating Station below in “Management’s Discussion and Analysis – Significant Trends and Regulation.” Adverse litigation outcomes 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 and climate-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 18 - Commitments and Contingencies, we are a co-owner of Colstrip Unit 4. The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Talen and Puget Sound Energy (Puget), a co-owner of Colstrip, have entered into a transaction in which Puget will transfer its 25% project share in Units 3 and 4 to Talen. The anticipated closing date of the transaction is December 31, 2025. On January 16, 2023 we entered into an agreement with Avista Corporation pursuant to which it will transfer to us its 15% project share in Units 3 and 4 on December 31, 2025.

The closure by third parties of Billings area generation (Corette) and Colstrip Units 1 and 2 reducing supply, together with increased customer load and the lack of dispatchable replacement generation in eastern Montana, has accelerated concerns about potential difficulties in physically serving parts of Montana including the Billings area. We are executing on multi-year plans for upgrades to the Billings area substations and other delivery infrastructure, but the addition of dispatchable generation in the area is also critical to reliable service in eastern Montana.

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. Worsening conditions as a result of climate change may increase the likelihood and magnitude of damages that may be caused by fires. 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 generation and market purchases to serve customers. The accredited capacity of our Montana portfolio of owned and long-term contracted electric generation resources covers 75 percent of our recent peak electric requirements, with remaining needs, including additional reserve margin, served through market purchases. In the past, Montana had been a net exporter of electric generation and we have relied upon Montana's excess generation for grid reliability and to physically serve customers. However, that situation in Montana has changed and we are predominantly a net importer, especially during peak demand. 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.

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 that might be associated with climate change, 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.

The physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

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. 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. 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 Energy Imbalance Market (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 could be direct targets of, or 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 have been analyzing our technology platforms and monitoring for signs of potential intrusions. We have also been reaching out to our vendors, suppliers and contractors requesting that they take 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, 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.

A pandemic or similar widespread public health concern could have a material negative impact on our business, financial condition and results of operations.

The actual or perceived effects of a disease outbreak, epidemic, pandemic or similar widespread public health concern, such as COVID-19, will likely negatively affect our business, financial condition and results of operations. The COVID-19 pandemic has had widespread impacts on people, economies, businesses and financial markets.

While the COVID-19 pandemic did not cause material disruptions to our operations, we could experience such disruptions in the future as a result of a pandemic (or a similar widespread public health concern) due to, among other things, quarantines, increased cyber risk due to employees working from home, worker absenteeism as a result of illness or other factors, social distancing measures and other travel, health-related, business or other restrictions. If a significant percentage of our workforce is unable to work, including because of illness, travel restrictions, or government mandates in connection with pandemics or disease outbreaks, our operations may be negatively affected.

Any such workforce implications and / or limitations or closures impact our ability to achieve our capital investment program and could have a material adverse impact on our ability to serve our customers and on our business, 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 $100 million of 1% Montana secured debt maturing in 2024. 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. The U.S. is a party to the United Nations' "Paris Agreement" on climate change, and that agreement along with other potential legislation and regulation discussed above, could result in enforceable GHG emission reduction requirements that could lead to increased compliance costs for us. For example, the EPA has indicated that it is currently "evaluating additional opportunities" to reduce GHG emissions from existing power plants.

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.

To the extent that any climate change adversely affects the national or regional economic health through physical impacts or increased rates caused by the inclusion of additional regulatory costs, CO_2 taxes or imposed costs, we may be adversely impacted. 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.

NorthWestern Energy Group is a holding company and relies on cash from its subsidiaries to pay dividends.

Through completion of a reorganization on January 1, 2024, NorthWestern Energy Group is a holding company parent entity and thus its primary assets are its 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.

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, hacking or internal security breaches could prevent us from fulfilling our critical business functions including delivering energy to our customers, and sensitive, confidential, and other data could be compromised. This could adversely affect our business, our financial condition, operating results or liquidity. For the year ended December 31, 2023, there have been no cybersecurity incidents with a material 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 periodically 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, 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.

We monitor potential risks associated with the use of third-party service providers and vendors. Our cyber incident monitoring process includes dialog with any third party or business partner potentially impacted by a disclosed incident. 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. In addition, we engage with 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 has experience in cybersecurity, hold 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 Montana electric and natural gas assets are subject to the lien of our Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of our South Dakota Mortgage Bond indenture.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 18 - 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 9, 2024, there were approximately 1,209 common stockholders of record.

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, 2023 compared to the year ended December 31, 2022, 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, 2022 compared with the year ended December 31, 2021, 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, 2022.

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 20 - 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 775,300 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 2023, 2022 and 2021. Following is a discussion of our strategy and significant trends.

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 2023, approximately 55 percent of our retail needs from our owned and long-term contracted resources originated from carbon-free resources, compared to approximately 40 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 recently entered into power purchase agreements with two solar projects totaling 160-megawatts that began delivering energy to our Montana customers in 2023. 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 2023 COMPARED TO OUR 2022 RESULTS

	Year Ended December 31, 2023 vs. 2022		
	Income Before Income Taxes	Income Tax Benefit (Expense)	Net Income
		(in millions)	
Year ended December 31, 2022	$ 182.4	$ 0.6	$ 183.0
*Variance in **revenue** and fuel, purchased supply, and direct transmission expense[(1)] items impacting net income:*			
Montana rate review - new base rates	32.6	(8.3)	24.3
Lower non-recoverable Montana electric supply costs	14.2	(3.6)	10.6
Montana property tax tracker collections	12.8	(3.2)	9.6
Higher Montana natural gas transportation	2.2	(0.6)	1.6
Higher electric transmission revenue	0.6	(0.2)	0.4
Lower natural gas retail volumes	(7.0)	1.8	(5.2)
Lower electric retail volumes	(1.8)	0.5	(1.3)
Higher revenue from lower production tax credits, offset within income tax benefit (expense)	3.8	(3.8)	—
Other	(1.7)	0.4	(1.3)
*Variance in **expense** items[(2)] impacting net income:*			
Higher depreciation expense	(15.5)	3.9	(11.6)
Higher interest expense	(14.5)	3.7	(10.8)
Higher operating, maintenance, and administrative expenses	(14.4)	3.6	(10.8)
Lower property and other taxes not recoverable within trackers	3.0	(0.8)	2.2
Other	4.9	(1.5)	3.4
Year ended December 31, 2023	$ 201.6	$ (7.5)	$ 194.1
Change in Net Income			$ 11.1

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

Consolidated net income in 2023 was $194.1 million as compared with $183.0 million in 2022. This increase was primarily due to new base rates resulting from the Montana rate review, lower non-recoverable Montana electric supply costs, higher Montana property tax tracker collections, and lower property and other taxes not recoverable within trackers, partly offset by lower electric and natural gas retail volumes, higher depreciation and depletion expense, higher interest expense, higher operating, maintenance, and administrative expenses, and higher income tax expense.

SIGNIFICANT TRENDS AND REGULATION

Regulatory Update

Rate reviews are necessary to recover the cost of providing safe, reliable service, while contributing to earnings growth and achieving our financial objectives. We regularly review the need for electric and natural gas rate relief in each state in which we provide service.

Montana Rate Review Filing – On October 27, 2023, the MPSC issued a final order approving the settlement agreement filed April 3, 2023. Final rates, adjusting from interim to settled rates, were effective November 1, 2023. For additional information related to our Montana Rate Review Filing, see Note 3 - Regulatory Matters to the Consolidated Financial Statements.

South Dakota Electric Rate Review Filing – In June 2023, we filed a South Dakota electric rate review filing (2022 test year) for an annual increase to electric rates totaling approximately $30.9 million. Our request was based on a rate of return of 7.54 percent, a capital structure including 50.5 percent equity, and rate base of $787.3 million. In January 2024, the SDPUC issued a final order approving the settlement agreement between NorthWestern and SDPUC Staff for an annual increase in base rates of approximately $21.5 million and an authorized rate of return of 6.81 percent. The approved settlement is based on a capital structure of 50.5 percent equity and a rate base of $791.8 million. Final rates were effective January 10, 2024. In addition, the SDPUC approved a phase in rate plan rider that allows for the recovery of capital investments not yet included in base rates.

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. In this reorganization, shareholders of NW Corp (the predecessor publicly held parent company) became shareholders of NorthWestern Energy Group, maintaining the same number of shares and ownership percentage as held in NW Corp immediately prior to the reorganization. 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. Immediately after consummation of the reorganization, NorthWestern Energy Group had, on a consolidated basis, the same assets, businesses and operations as NW Corp had immediately prior to the consummation of the reorganization. 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. On January 1, 2024, we completed the second and final phase of the holding company reorganization. NW Corp contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NWE Public Service, and then distributed its equity interest in NWE Public Service and certain other subsidiaries to NorthWestern Energy Group, resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group.

Power Costs and Credits Adjustment Mechanism - The MPSC's September 2022 decision approving interim rates related to our Montana rate review included a $61.1 million increase to the PCCAM Base, from $138.7 million to $199.8 million, effective October 1, 2022. The MPSC's October 2023 decision approving the Montana rate review settlement agreement increased the PCCAM Base to $208.4 million, with retroactive application to July 1, 2022. We have under-collected our total Montana electric supply costs for the July 2022 through June 2023 PCCAM year by approximately $14.5 million, which includes a $2.9 million increase to our under-collection for this tracker period to reflect the retroactive application of the higher PCCAM Base rates effective July 1, 2022. As of December 31, 2023, we have over-collected our total Montana electric supply costs for the July 2023 through June 2024 PCCAM year by approximately $4.7 million.

Under the PCCAM, net costs higher or lower than the PCCAM Base (excluding QF costs) are allocated 90 percent to Montana customers and 10 percent to shareholders. For the twelve months ended December 31, 2023, we over collected supply costs of $32.9 million resulting in a reduction to our under collection of costs, and recorded an increase in pre-tax earnings of $7.0 million (10 percent of the PCCAM Base cost variance), which is inclusive of a $3.2 million increase in pre-tax earnings related to the retroactive application of higher PCCAM Base rates to July 1, 2022. For the twelve months ended December 31, 2022, we under collected costs of $64.8 million resulting in an increase to the under collection of costs, and recorded a reduction in pre-tax earnings of $7.2 million.

As discussed above, the approved Montana rate review settlement provides for an update to the PCCAM by adjusting the base costs from $138.7 million to $208.4 million and providing for more timely quarterly recovery of deferred balances instead of annual recovery. The updated $208.4 million PCCAM Base is retroactive to an effective date of July 1, 2022.

Our electric supply from owned and long-term contracted resources is not adequate to meet our peak-demand needs. Because of this, the volatility of market prices for energy on peak-demand days, even if only for a few days in duration, exposes us to potentially significant market purchases that could negatively impact our results of operations and cash flows. See the Electric Resource Planning - Montana section below for how we are working to address this market exposure.

Electric Resource Planning - Montana

Yellowstone County 175 MW plant - Construction of the new generation facility continues to progress and we expect the plant to be operational no later than the end of the third quarter 2024. The lawsuit challenging the YCGS air quality permit, which required us to suspend construction activities for a period of time, as well as additional related legal and construction challenges, delayed the project timing and have increased costs. As of December 31, 2023, total costs of approximately $240.0 million have been incurred, with expected total costs of approximately $310.0 million to $320.0 million. See Note 18 - Commitments and Contingencies to the Consolidated Financial Statements included herein for additional information regarding legal challenges impacting YCGS.

Acquisition of Colstrip Interest - On January 16, 2023, we entered into a definitive agreement (the Avista Agreement) with Avista Corporation (Avista) to acquire Avista's 15 percent interest in each of Units 3 and 4 at the Colstrip Generating Station, a coal-fired, base-load electric generation facility located in Colstrip, Montana. The Avista Agreement provides that the purchase price will be $0 and that we will acquire Avista's interest effective December 31, 2025, subject to the satisfaction of the closing conditions contained within the Avista Agreement. Under the terms of this Avista Agreement, we will be responsible for operating costs starting on January 1, 2026; while Avista will retain responsibility for its 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 decommission and demolition costs associated with the existing facilities that comprise Avista's interest.

The Avista Agreement contains customary representations and warranties, covenants, and indemnification obligations, and the Avista Agreement is subject to customary conditions and approvals, including approval from the FERC. Closing also is conditioned on our ability to enter into a new coal supply agreement for Colstrip by December 31, 2024. Such coal supply agreement must provide a sufficient amount of coal to Colstrip to permit the generation of electric power by the maximum permitted capacity of the interest in Colstrip then held by us during the period from January 1, 2026 through, December 31, 2030.

Either party may terminate the Avista Agreement if any requested regulatory approval is denied or if the closing has not occurred by December 31, 2025 or if any law or order would delay or impair closing.

The acquisition of an additional interest under this Avista Agreement in 2026 will provide capacity to help us meet our obligation to provide reliable and cost effective power to our customers in Montana, while allowing opportunity for us to identify and plan for newer technologies to provide reliable, affordable and carbon free power through our IRP process.

Future Integrated Resource Planning - Resource adequacy in the Western third of the U.S. has been declining with the retirement of thermal power plants. Our owned and long-term contracted resources are inadequate to supply the necessary capacity we require to meet our peak-demand loads, which exposes us to large quantities of market purchases at typically high and volatile energy prices. To comply with regulatory resource planning requirements, we submitted an IRP to the MPSC on April 28, 2023.

We remain concerned regarding an overall lack of capacity in the West and our owned and long-term contracted capacity deficit to meet peak-demand loads. The construction of the Yellowstone County Generating Station and acquisition of Avista's Colstrip Units 3 and 4 interests are expected to reduce our exposure to market purchases.

Proposed EPA Rules

In May 2023, the EPA proposed new GHG emissions standards for coal and natural gas-fired plants. In particular, the proposed rules would (i) strengthen the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establish emission guidelines for states to follow in limiting carbon pollution from existing fossil fuel-fired steam generating electric generating units (including coal, oil and natural gas-fired units); and (iii) establish emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired). In addition, in April 2023, EPA proposed to amend the MATS. Among other things, MATS currently sets stringent emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. We are in compliance with existing MATS requirements. The proposed amendment of the MATS would strengthen the MATS requirements, and if adopted as written, both the GHG and MATS proposed rules could have a material negative impact on our coal-fired plants, including requiring potentially expensive upgrades or the early retirement of Colstrip Unit's 3 and 4 due to the rules making the facility uneconomic.

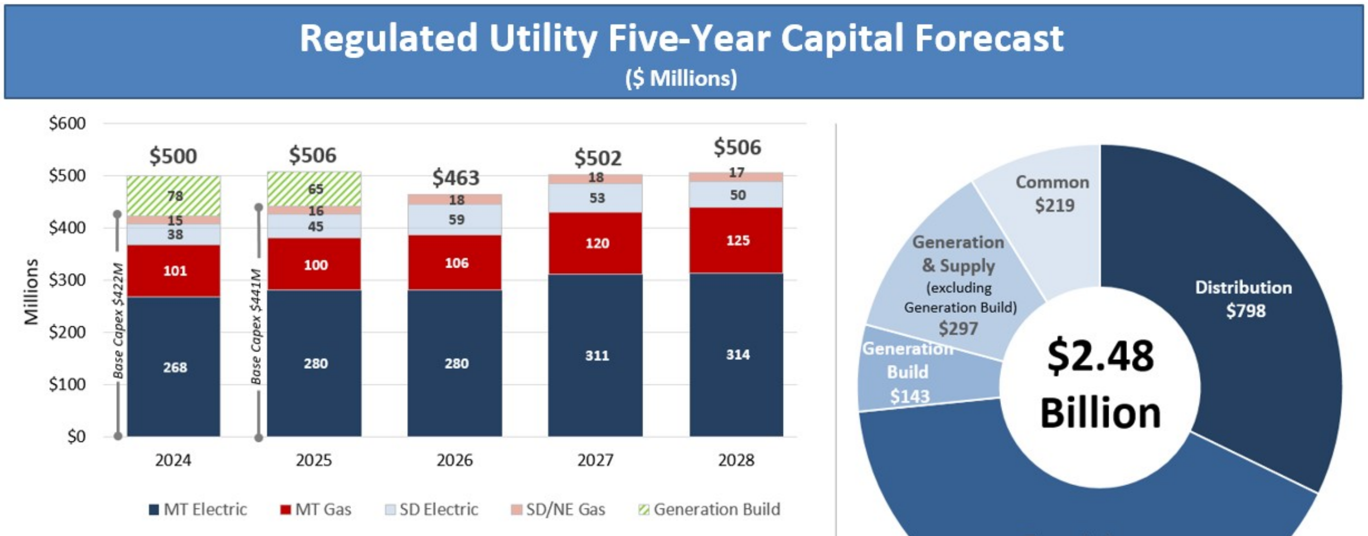
Previous efforts by the EPA were met with extensive litigation and we anticipate a similar response if the proposed rules are adopted. As MATS and GHG regulations are implemented, it could result in additional material compliance costs. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any MATS or GHG regulations that, in our view, disproportionately impact customers in our region.

Electric Resource Supply - South Dakota

Our electric supply resource plans for South Dakota continue to identify portfolio requirements including potential investments resulting from a completed competitive solicitation process. We anticipate filing the next resource plan in the summer of 2024.

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	2024	2025	2026	2027	2028
Electric	384	390	339	364	364
Natural Gas	116	116	124	138	142
Total Capital Forecast	**$500**	**$506**	**$463**	**$502**	**$506**

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. Over $1.8 billion or 75 percent of our capital forecast above is projected to be spent on our distribution and transmission system. Beginning in 2021, and continuing through 2025, we expect to install automated metering infrastructure in Montana at a total cost of approximately $134.0 million, of which $41.7 million remains and is reflected in the five year capital forecast above.

RESULTS OF OPERATIONS

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

Factors Affecting Results of Operations

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

Revenues are also impacted by customer growth and usage, the latter of which is primarily affected by weather and the impact of energy efficiency initiatives and investment. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

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

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

OVERALL CONSOLIDATED RESULTS

Year Ended December 31, 2023 Compared with Year Ended December 31, 2022

Consolidated net income in 2023 was $194.1 million as compared with $183.0 million in 2022, an increase of $11.1 million. As described in more detail below, this increase was primarily due to new base rates resulting from the Montana rate review, lower non-recoverable Montana electric supply costs, higher Montana property tax tracker collections, and lower property and other taxes not recoverable within trackers, partly offset by lower electric and natural gas retail volumes, higher depreciation and depletion expense, higher interest expense, higher operating, maintenance, and administrative expenses, and higher income tax expense.

Consolidated gross margin in 2023 was $416.3 million as compared with $376.9 million in 2022, an increase of $39.4 million or 10.5 percent. This increase was primarily due to new base rates resulting from the Montana rate review, lower non-recoverable Montana electric supply costs, higher Montana property tax tracker collections, and lower property and other taxes not recoverable within trackers, partly offset by lower electric and natural gas retail volumes, higher depreciation and depletion expense, and higher operating and maintenance expense.

	Electric		Natural Gas		Total	
	2023	2022	2023	2022	2023	2022
			(in millions)			
Reconciliation of gross margin to utility margin:						
Operating Revenues	$1,068.8	$1,106.5	$ 353.3	$ 371.3	$1,422.1	$1,477.8
Less: Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	262.7	324.4	157.5	167.6	420.2	492.0
Less: Operating and maintenance	166.0	167.8	54.5	53.6	220.5	221.4
Less: Property and other taxes	120.3	149.8	34.3	42.7	154.6	192.5
Less: Depreciation and depletion	174.1	162.4	36.4	32.6	210.5	195.0
Gross Margin	**345.7**	**302.1**	**70.6**	**74.8**	**416.3**	**376.9**
Operating and maintenance	166.0	167.8	54.5	53.6	220.5	221.4
Property and other taxes	120.3	149.8	34.3	42.7	154.6	192.5
Depreciation and depletion	174.1	162.4	36.4	32.6	210.5	195.0
Utility Margin(1)	**$ 806.1**	**$ 782.1**	**$ 195.8**	**$ 203.7**	**$1,001.9**	**$ 985.8**

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

	Year Ended December 31,			
	2023	2022	Change	% Change
		(in millions)		
Utility Margin				
Electric	$ 806.1	$ 782.1	$ 24.0	3.1 %
Natural Gas	195.8	203.7	(7.9)	(3.9)
Total Utility Margin(1)	**$ 1,001.9**	**$ 985.8**	**$ 16.1**	**1.6 %**

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

Consolidated utility margin in 2023 was $1,001.9 million as compared with $985.8 million in 2022, an increase of $16.1 million, or 1.6 percent.

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

	Utility Margin 2023 vs. 2022	
Utility Margin Items Impacting Net Income		
Montana rate review - new base rates	$	32.6
Lower non-recoverable Montana electric supply costs		14.2
Montana property tax tracker collections		12.8
Higher Montana natural gas transportation		2.2
Higher electric transmission revenue due to market conditions		0.6
Lower natural gas retail volumes		(7.0)
Lower electric retail volumes		(1.8)
Other		(1.7)
Change in Utility Margin Impacting Net Income		**51.9**
Utility Margin Items Offset Within Net Income		
Lower property taxes recovered in revenue, offset in property tax expense		(35.8)
Lower operating expenses recovered in revenue, offset in operating and maintenance expense		(3.1)
Lower gas production taxes recovered in revenue, offset in property and other taxes		(0.7)
Higher revenue from lower production tax credits, offset in income tax expense		3.8
Change in Items Offset Within Net Income		**(35.8)**
Increase in Consolidated Utility Margin(1)	**$**	**16.1**

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

Lower non-recoverable Montana electric supply costs were driven by higher electric supply revenues, lower electric supply costs, and $3.2 million for the retroactive application of higher PCCAM base rates approved in the Montana rate review.

Lower electric retail volumes were driven by unfavorable weather in Montana impacting residential demand and lower commercial demand as compared to the prior year, partly offset by customer growth. Lower natural gas retail volumes were driven by unfavorable weather in Montana, partly offset by favorable weather in Nebraska and customer growth.

	Year Ended December 31,						
	2023		2022		Change		% Change
	(in millions)						
Operating Expenses (excluding fuel, purchased supply and direct transmission expense)							
Operating and maintenance	$	220.5	$	221.4	$	(0.9)	(0.4) %
Administrative and general		117.3		113.8		3.5	3.1
Property and other taxes		153.1		192.5		(39.4)	(20.5)
Depreciation and depletion		210.5		195.0		15.5	7.9
Total Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$**	**701.4**	**$**	**722.7**	**$**	**(21.3)**	**(2.9)%**

Consolidated operating expenses, excluding fuel, purchased supply and direct transmission expense, were $701.4 million in 2023, as compared with $722.7 million in 2022. Primary components of the change include the following (in millions):

		Operating Expenses 2023 vs. 2022
Operating Expenses (excluding fuel, purchased supply and direct transmission expense) Impacting Net Income		
Higher depreciation expense due to plant additions	$	15.5
Higher labor and benefits expense, partly offset by higher capitalization of labor and benefits costs[(1)]		6.1
Higher insurance expense		2.1
Increase in uncollectible accounts		1.1
Higher expenses at our electric generation facilities		1.0
Higher cost of materials		0.8
Lower property and other taxes not recoverable within trackers		(3.0)
Other		3.3
Change in Items Impacting Net Income		**26.9**
Operating Expenses Offset Within Net Income		
Lower property and other taxes recovered in trackers, offset in revenue		(35.8)
Lower pension and other postretirement benefits, offset in other income[(1)]		(8.7)
Lower operating expenses recovered in trackers, offset in revenue		(3.1)
Lower natural gas production taxes recovered in trackers, offset in revenue		(0.7)
Higher deferred compensation, offset in other income		0.1
Change in Items Offset Within Net Income		**(48.2)**
Decrease in Operating Expenses (excluding fuel, purchased supply and direct transmission expense)	**$**	**(21.3)**

(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 2023 was $300.5 million as compared with $263.1 million in 2022. This increase was primarily due to new base rates resulting from the Montana rate review, lower non-recoverable Montana electric supply costs, higher Montana property tax tracker collections, and lower property and other taxes not recoverable within trackers, partly offset by lower electric and natural gas retail volumes, higher depreciation and depletion expense, and higher operating, maintenance, and administrative expense.

Consolidated interest expense in 2023 was $114.6 million, as compared with $100.1 million in 2022. This increase was due to higher borrowings and interest rates, partly offset by higher capitalization of AFUDC.

Consolidated other income in 2023 was $15.8 million, as compared with $19.4 million in 2022. This decrease was primarily due to an increase in the non-service cost component of pension expense, partly offset by the prior year CREP penalty and higher capitalization of AFUDC.

Consolidated income tax expense in 2023 was $7.5 million, as compared to an income tax benefit of $0.6 million in 2022. Our effective tax rate for the twelve months ended December 31, 2023 was 3.7 percent as compared with (0.3) percent for the same period of 2022. Income tax expense for the twelve months ended December 31, 2023, includes a one-time $3.2 million expense for the reduction of previously claimed alternative minimum tax credits as well as a $3.2 million benefit related to a reduction in our unrecognized tax benefits. We currently estimate our effective tax rate will range between 12.0 percent to 14.0 percent in 2024. Based on the significant NOL we generated during the year ended December 31, 2023, we anticipate paying minimal cash for income taxes into 2028.

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

	Year Ended December 31,			
	2023		2022	
Income Before Income Taxes	$ 201.6		$ 182.4	
Income tax calculated at federal statutory rate	42.4	21.0 %	38.3	21.0 %
Permanent or flow through adjustments:				
State income taxes, net of federal provisions	0.6	0.3	0.6	0.3
Flow-through repairs deductions	(25.9)	(12.9)	(22.7)	(12.4)
Production tax credits	(10.3)	(5.1)	(13.2)	(7.2)
Unregulated Tax Cuts and Jobs Act excess deferred income taxes	(3.4)	(1.7)	—	—
Release of unrecognized tax benefits	(3.2)	(1.6)	—	—
Amortization of excess deferred income taxes	(2.2)	(1.1)	(1.7)	(0.9)
Plant and depreciation of flow through items	6.6	3.3	(0.2)	(0.1)
Reduction to previously claimed alternative minimum tax credit	3.2	1.6	—	—
Prior year permanent return to accrual adjustments	0.0	0.0	(1.4)	(0.8)
Other, net	(0.3)	(0.1)	(0.3)	(0.2)
	(34.9)	(17.3)	(38.9)	(21.3)
Income Tax Expense (Benefit)	$ 7.5	3.7 %	$ (0.6)	(0.3)%

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, 2023 Compared with Year Ended December 31, 2022

	Revenues		Change		MWHs		Avg. Customer Counts	
	2023	2022	$	%	2023	2022	2023	2022
	(in thousands)							
Montana	$ 408,341	$ 357,384	$ 50,957	14.3 %	2,795	2,868	322,489	316,968
South Dakota	67,888	69,809	(1,921)	(2.8)	603	596	51,261	51,069
Residential	**476,229**	**427,193**	**49,036**	**11.5**	**3,398**	**3,464**	**373,750**	**368,037**
Montana	431,357	368,634	62,723	17.0	3,238	3,237	74,438	73,093
South Dakota	103,194	108,202	(5,008)	(4.6)	1,101	1,114	12,973	12,897
Commercial	**534,551**	**476,836**	**57,715**	**12.1**	**4,339**	**4,351**	**87,411**	**85,990**
Industrial	45,958	39,773	6,185	15.6	2,660	2,590	79	76
Other	32,756	31,007	1,749	5.6	134	161	6,443	6,406
Total Retail Electric	**$1,089,494**	**$ 974,809**	**$ 114,685**	**11.8 %**	**10,531**	**10,566**	**467,683**	**460,509**
Regulatory amortization	(105,608)	46,382	(151,990)	(327.7)				
Transmission	78,436	77,791	645	0.8				
Wholesale and Other	6,511	7,583	(1,072)	(14.1)				
Total Revenues	**$1,068,833**	**$1,106,565**	**$ (37,732)**	**(3.4)%**				
Fuel, purchased supply and direct transmission expense(1)	**262,755**	**324,434**	**(61,679)**	**(19.0)**				
Utility Margin(2)	**$ 806,078**	**$ 782,131**	**$ 23,947**	**3.1 %**				

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

	Cooling Degree Days			2023 as compared with:	
	2023	2022	Historic Average	2022	Historic Average
Montana	441	602	455	27% cooler	3% cooler
South Dakota	1,035	953	752	9% warmer	38% warmer

	Heating Degree Days			2023 as compared with:	
	2023	2022	Historic Average	2022	Historic Average
Montana(1)	7,237	8,004	7,592	10% warmer	5% warmer
South Dakota	7,665	7,687	7,675	remained flat	remained flat

(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, 2023 and 2022 (in millions):

		Utility Margin 2023 vs. 2022
Utility Margin Items Impacting Net Income		
Montana rate review - new electric base rates	$	29.5
Lower non-recoverable Montana electric supply costs		14.2
Montana property tax tracker collections		9.5
Higher electric transmission revenue due to market conditions		0.6
QF liability adjustment		(0.1)
Lower retail volumes		(1.8)
Other		(0.3)
Change in Utility Margin Items Impacting Net Income		**51.6**
Utility Margin Items Offset Within Net Income		
Lower property taxes recovered in revenue, offset in property tax expense		(28.1)
Lower operating expenses recovered in revenue, offset in operating and maintenance expense		(3.3)
Higher revenue from lower production tax credits, offset in income tax expense		3.8
Change in Items Offset Within Net Income		**(27.6)**
Increase in Utility Margin[(1)]	**$**	**24.0**

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

Lower non-recoverable Montana electric supply costs were driven by higher electric supply revenues, lower electric supply costs, and $3.2 million for the retroactive application of higher PCCAM base rates approved in the Montana rate review.

Lower retail volumes were driven by unfavorable weather in Montana impacting residential demand and lower commercial demand as compared to the prior year, partly offset by customer growth.

The adjustment to our electric QF liability (unrecoverable costs associated with contracts covered by the Public Utility Regulatory Policies Act of 1978 (PURPA) as part of a 2002 stipulation with the MPSC and other parties) reflects a $5.0 million gain in 2023, as compared with a $5.1 million gain for the same period in 2022, due to the combination of:

- A $0.8 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $1.8 million favorable reduction in costs in the prior period; and
- A favorable adjustment, decreasing the QF liability by $4.2 million, reflecting annual actual contract price escalation for the 2023-2024 contract year, which was less than previously estimated. The 2023-2024 contract year is the last year of the contract that contains variable pricing terms. This is compared to a favorable adjustment of $3.3 million in the prior year due to less than previously estimated actual price escalation.

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, 2023 Compared with Year Ended December 31, 2022

	Revenues		Change		Dekatherms		Avg. Customer Counts	
	2023	2022	$	%	2023	2022	2023	2022
			(in thousands)					
Montana	$ 136,097	$ 152,343	(16,246)	(10.7) %	14,008	15,319	183,810	181,879
South Dakota	36,638	39,178	(2,540)	(6.5)	3,179	3,280	42,053	41,524
Nebraska	35,539	35,756	(217)	(0.6)	2,581	2,558	37,793	37,693
Residential	**208,274**	**227,277**	**(19,003)**	**(8.4)**	**19,768**	**21,157**	**263,656**	**261,096**
Montana	73,721	79,274	(5,553)	(7.0)	8,036	8,329	25,725	25,319
South Dakota	25,869	28,487	(2,618)	(9.2)	3,169	2,981	7,232	7,058
Nebraska	22,114	22,071	43	0.2	1,916	1,846	5,023	5,003
Commercial	**121,704**	**129,832**	**(8,128)**	**(6.3)**	**13,121**	**13,156**	**37,980**	**37,380**
Industrial	1,392	1,520	(128)	(8.4)	157	163	232	232
Other	1,681	1,932	(251)	(13.0)	209	232	190	178
Total Retail Gas	**$ 333,051**	**$ 360,561**	**$ (27,510)**	**(7.6)%**	**33,255**	**34,708**	**302,058**	**298,886**
Regulatory amortization	(25,012)	(27,964)	2,952	(10.6)				
Wholesale and other	45,271	38,675	6,596	17.1				
Total Revenues	**$ 353,310**	**$ 371,272**	**$ (17,962)**	**(4.8)%**				
Fuel, purchased supply and direct transmission expense(1)	**157,507**	**167,577**	**(10,070)**	**(6.0)**				
Utility Margin(2)	**$ 195,803**	**$ 203,695**	**$ (7,892)**	**(3.9)%**				

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

	Heating Degree Days			2023 as compared with:	
	2023	2022	Historic Average	2022	Historic Average
Montana(1)	7,478	8,194	7,791	9% warmer	4% warmer
South Dakota	7,665	7,687	7,675	remained flat	remained flat
Nebraska	5,893	5,767	6,044	2% colder	2% warmer

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

The following summarizes the components of the changes in natural gas utility margin for the years ended December 31, 2023 and 2022 (in millions):

	Utility Margin 2023 vs. 2022
Utility Margin Items Impacting Net Income	
Montana property tax tracker collections	$ 3.3
Montana rate review - new natural gas base rates	3.1
Higher Montana natural gas transportation	2.2
Lower retail volumes	(7.0)
Other	(1.3)
Change in Utility Margin Impacting Net Income	**0.3**
Utility Margin Items Offset Within Net Income	
Lower property taxes recovered in revenue, offset in property tax expense	(7.7)
Lower gas production taxes recovered in revenue, offset in property and other taxes	(0.7)
Higher operating expenses recovered in revenue, offset in operating and maintenance expense	0.2
Change in Items Offset Within Net Income	**(8.2)**
Decrease in Utility Margin[(1)]	**$ (7.9)**

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

Lower retail volumes were driven by unfavorable weather in Montana, partly offset by favorable weather in Nebraska and customer growth.

Our wholesale and other revenues are largely utility margin neutral as they are offset by changes in fuel, purchased supply and direct transmission expenses.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. For NorthWestern Energy Group, liquidity is primarily provided through its revolving credit facility and dividends from its utility operating subsidiaries, NW Corp and NWE Public Service. These subsidiaries are subject to certain restrictions that may limit the amount of their dividend distributions. See Note 16 - Common Stock 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, 2023, our total consolidated net liquidity was approximately $241.2 million, including $9.2 million of cash and $232.0 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,	
	2023	2022
Operating Activities		
Net income	$ 194.1	$ 183.0
Non-cash adjustments to net income	210.1	183.1
Changes in working capital	115.6	(37.0)
Other noncurrent assets and liabilities	(30.6)	(21.9)
Cash Provided by Operating Activities	**489.2**	**307.2**
Investing Activities		
Property, plant and equipment additions	(566.9)	(515.1)
Investment in equity securities	(3.9)	(1.7)
Cash Used in Investing Activities	**(570.8)**	**(516.8)**
Financing Activities		
Proceeds from issuance of common stock, net	73.6	277.0
Issuance of long-term debt	300.0	—
Dividends on common stock	(154.1)	(140.1)
Line of credit (repayments) borrowings, net	(132.0)	77.0
Financing costs	(4.3)	(1.2)
Other	1.1	0.6
Cash Provided by Financing Activities	**84.3**	**213.3**
Net Increase in Cash, Cash Equivalents, and Restricted Cash	**$ 2.7**	**$ 3.7**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 22.5	$ 18.8
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 25.2**	**$ 22.5**

Operating Activities

As of December 31, 2023, cash, cash equivalents, and restricted cash were $25.2 million as compared with $22.5 million as of December 31, 2022. Cash provided by operating activities totaled $489.2 million for the year ended December 31, 2023 as compared with $307.2 million for the year ended December 31, 2022. As shown in the table below, this increase in operating cash flows is primarily due to a $123.9 million improvement in net cash inflows for previously uncollected energy supply costs and interim and final rates from our Montana rate review.

Net under-collected supply costs (in millions)

	Beginning of year	End of year	Net cash inflows
2022	$ 99.1	$ 115.4	$ (16.3)
2023	$ 115.4	$ 7.8	$ 107.6
		Improvement in annual net cash inflows	$ 123.9

As discussed above, on October 27, 2023 the MPSC issued their final order approving our Montana rate review settlement which included an update to the PCCAM by adjusting the base costs from $138.7 million to $208.4 million and providing for more timely quarterly recovery of deferred balances instead of annual recovery. The updated $208.4 million PCCAM Base is retroactive to an effective date of July 1, 2022. As of December 31, 2023, we have under-collected our total Montana electric supply costs for the July 2022 through June 2023 PCCAM year by approximately $14.5 million that we began collecting in October 2023. As of December 31, 2023, we have over-collected our total Montana electric supply costs for the July 2023 through June 2024 PCCAM year by approximately $4.7 million.

With the adjusted PCCAM Base, we anticipate continued improvements in our cash flows from operations. However, continued higher overall market prices, which could be further exacerbated by extreme weather events, could create additional costs with deferred recovery that would offset these anticipated cash flow improvements.

Investing Activities

Cash used in investing activities totaled $570.8 million during the year ended December 31, 2023, as compared with $516.8 million during 2022. Plant additions during 2023 include capital maintenance additions of approximately $321.9 million and capacity related capital expenditures of approximately $245.0 million. Plant additions during 2022 included capital maintenance additions of approximately $295.4 million and capacity related capital expenditures of approximately $219.7 million. As discussed above in the "Significant Infrastructure Investments and Initiatives" section, our capital expenditures are forecasted to be $500 million in 2024.

Financing Activities

Cash provided by financing activities totaled $84.3 million during the year ended December 31, 2023 as compared with $213.3 million during the year ended December 31, 2022. During the year ended December 31, 2023, cash provided by financing activities reflects net proceeds from the issuance of debt of $300.0 million and proceeds received from the issuance of common stock of $73.6 million, partly offset by payment of dividends of $154.1 million and net repayments under our revolving lines of credit of $132.0 million. During the year ended December 31, 2022, cash provided by financing activities reflects proceeds received from the issuance of common stock of $277.0 million and net issuances under our revolving lines of credit of $77.0 million, partly offset by payment of dividends of $140.1 million.

Cash Requirements and Capital Resources

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

Our material cash requirements are also related to investment in our business through our capital expenditure program, which is discussed above in the “Significant Infrastructure Investments and Initiatives” section. Our capital expenditures are forecasted to be $500 million in 2024, $506 million in 2025, and $463 million in 2026. We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt issuances and future rate increases. 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.

Credit Facilities

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

For further information on our credit facilities, see Note 10 - Unsecured Credit Facilities 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, 2023 (in millions):

Amount outstanding at year end	$	318.0
Daily average amount outstanding	$	228.4
Maximum amount outstanding	$	490.0
Minimum amount outstanding	$	54.0

As discussed further within Note 10 - Unsecured Credit Facilities, our credit facility availability as of December 31, 2023 was $232.0 million. With the completion of the holding company reorganization and associated restructuring of our credit facilities on January 1, 2024, our total credit facility availability increased by $50.0 million to $282.0 million.

As of February 9, 2024, availability under our revolving credit facilities was approximately $325.0 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 $100 million of debt maturing in 2024, which we intend to refinance.

For further information on our long-term debt, see Note 11 - 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 16 - 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 9, 2024, our current ratings with these agencies are as follows:

	Issuer Rating	Senior Secured Rating	Senior Unsecured Rating	Outlook
NorthWestern Energy Group				
Fitch[(1)(2)]	BBB	-	BBB	Stable
Moody's	-	-	-	-
S&P[(2)]	BBB	-	-	Stable
NW Corp				
Fitch[(1)(2)]	BBB	A-	BBB+	Stable
Moody's[(2)]	Baa2	A3	Baa2	Stable
S&P[(2)]	BBB	A-	-	Stable
NWE Public Service				
Fitch[(1)(2)]	BBB	A-	BBB+	Stable
Moody's[(2)]	Baa2	A3	-	Stable
S&P[(2)]	BBB	A-	-	Stable

(1) This Fitch Issuer Rating represents the Issuer Default Rating.
(2) As part of completing the holding company reorganization, NorthWestern Energy Group and NWE Public Service received their credit ratings from these agencies in December 2023. These agencies also affirmed their ratings for NW Corp.

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, 2023. See additional discussion in Note 18 - Commitments and Contingencies to the Consolidated Financial Statements.

	Total	2024	2025	2026	2027	2028	Thereafter
				(in thousands)			
Long-term debt[(1)]	$ 2,797,660	$ 100,000	$ 300,000	$ 105,000	$ —	$ 497,660	$ 1,795,000
Finance leases	8,799	3,338	3,596	1,865	—	—	—
Estimated pension and other postretirement obligations[(2)]	57,402	12,554	11,437	11,137	11,137	11,137	N/A
QF liability[(3)]	303,062	74,110	60,360	55,393	56,665	42,400	14,134
Supply and capacity contracts[(4)]	2,828,615	321,853	244,091	263,407	243,576	225,916	1,529,772
Contractual interest payments on debt[(5)]	1,592,745	123,354	114,385	108,295	106,636	101,968	1,038,107
Commitments for significant capital projects[(6)]	45,945	45,945	—	—	—	—	$ —
Total Commitments[(7)]	$ 7,634,228	$ 681,154	$ 733,869	$ 545,097	$ 418,014	$ 879,081	$ 4,377,013

(1) Represents cash payments for long-term debt and excludes $13.1 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 $67 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $303.1 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $266.5 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 energy supply costs incurred under these contracts are generally recoverable through rate mechanisms approved by the MPSC, as further described in Note 3 - Regulatory Matters.
(5) Contractual interest payments include our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 6.71 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 uncertain tax positions as they are not practicable to estimate. Additionally, the table above excludes reserves for environmental remediation (See Note 18 - Commitments and Contingencies) and AROs (see Note 6 - 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 $15.7 million and $17.3 million as of December 31, 2023 and 2022, 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 4 - 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 14 - 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, 2023, our discount rate on both the NorthWestern Corporation pension plan and NorthWestern Energy pension plan is 4.95-5.00 percent.

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 5.15% percent and 6.65% percent on the NorthWestern Corporation and NorthWestern Energy pension plan, respectively, for 2024.

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 %	$ 14	$ (12,846)
Discount rate decrease	(0.25)%	1,059	13,473
Rate of return on plan assets increase	0.25 %	(1,040)	N/A
Rate of return on plan assets decrease	(0.25)%	1,040	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. We have unrecognized tax benefits of approximately $28.1 million as of December 31, 2023. 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 12 - 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, 2023, we had $318.0 million in borrowings under our revolving credit facilities. A 1.0 percent increase in interest rates would increase our annual interest expense by approximately $3.2 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 and, in Montana, a sharing mechanism.

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 and under gas transportation agreements. 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 are 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, 2023, 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, 2023. 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, 2023, 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-4.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2023, 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 2024 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 2024 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 2024 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 2024 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 2024 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:

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).
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, date October 2, 2023).
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).
4.2(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).
4.3(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.
10.1(b) †	NorthWestern Corporation Key Employee Severance Plan 2016 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 25, 2016, 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 19, 2018, Commission File No. 1-10499).
10.1(d) †	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 23, 2019, 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 22, 2020, 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 11, 2021, Commission File No. 1-10499).
10.1(g) †	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(h) †	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 10, 2022, Commission File No. 1-10499).
10.1(i) †	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(j) †	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(k) †	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(l) †	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(m) †	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(n) †	NorthWestern Energy Group, Inc. Amended and Restated Equity Compensation Plan, as amended and restated 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(o) †	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).
10.2(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).
10.3(a)	Engineering, Procurement, and Construction Contract, dated April 19, 2021, between Northwestern Energy and Burns & McDonnell Engineering Company, Inc. (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, Commission File No. 1-10499).
10.3(b)	Procurement Contract, dated April 19, 2021, between Northwestern Energy and Caterpillar Power Generation Systems, LLC (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, Commission File No. 1-10499).
10.4(a)	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).
10.5	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).
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.
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 15, 2024	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
Dana J. Dykhouse	Chairman of the Board	February 15, 2024
/s/ BRIAN B. BIRD Brian B. Bird	President, Chief Executive Officer and Director (Principal Executive Officer)	February 15, 2024
/s/ CRYSTAL D. LAIL Crystal D. Lail	Vice President and Chief Financial Officer (Principal Financial Officer)	February 15, 2024
/s/ JEFFREY B. BERZINA Jeffrey B. Berzina	Controller (Principal Accounting Officer)	February 15, 2024
/s/ ANTHONY T. CLARK Anthony T. Clark	Director	February 15, 2024
/s/ JAN R. HORSFALL Jan R. Horsfall	Director	February 15, 2024
/s/ BRITT E. IDE Britt E. Ide	Director	February 15, 2024
/s/ KENT T. LARSON Kent T. Larson	Director	February 15, 2024
/s/ LINDA G. SULLIVAN Linda G. Sullivan	Director	February 15, 2024
/s/ MAHVASH YAZDI Mahvash Yazdi	Director	February 15, 2024
/s/ JEFFREY W. YINGLING Jeffrey W. Yingling	Director	February 15, 2024
/s/ SHERINA M. EDWARDS Sherina M. Edwards	Director	February 15, 2024

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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, 2023, 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 14, 2024, 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, 3 and 4 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 14, 2024
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, 2023, 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, 2023, 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, 2023, of the Company and our report dated February 14, 2024, 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 14, 2024

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2023	**2022**	**2021**
Revenues			
Electric	$ 1,068,833	$ 1,106,565	$ 1,052,182
Gas	353,310	371,272	320,134
Total Revenues	1,422,143	1,477,837	1,372,316
Operating Expenses			
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	420,262	492,011	425,548
Operating and maintenance	220,524	221,427	208,303
Administrative and general	117,360	113,776	101,873
Property and other taxes	153,068	192,524	173,444
Depreciation and depletion	210,474	195,020	187,467
Total Operating Expenses	1,121,688	1,214,758	1,096,635
Operating Income	300,455	263,079	275,681
Interest Expense, net	(114,617)	(100,110)	(93,674)
Other Income, net	15,832	19,434	8,252
Income Before Income Taxes	201,670	182,403	190,259
Income Tax (Expense) Benefit	(7,539)	605	(3,419)
Net Income	$ 194,131	$ 183,008	$ 186,840
Average Common Shares Outstanding	60,321	55,769	51,709
Basic Earnings per Average Common Share	$ 3.22	$ 3.28	$ 3.61
Diluted Earnings per Average Common Share	$ 3.22	$ 3.25	$ 3.60

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2023	2022	2021
Net Income	$ 194,131	$ 183,008	$ 186,840
Other comprehensive income (loss), net of tax:			
Reclassification of net losses on derivative instruments	452	452	452
Postretirement medical liability adjustment	(262)	(982)	(436)
Foreign currency translation	2	(8)	(57)
Total Other Comprehensive Income (Loss)	192	(538)	(41)
Comprehensive Income	$ 194,323	$ 182,470	$ 186,799

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	As of December 31,	
	2023	**2022**
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,164	$ 8,489
Restricted cash	16,023	13,974
Accounts receivable, net	212,257	244,952
Inventories	114,539	107,359
Regulatory assets	29,626	136,009
Prepaid expenses and other	25,397	28,041
Total current assets	**407,006**	**538,824**
Property, plant, and equipment, net	6,039,801	5,657,480
Goodwill	357,586	357,586
Regulatory assets	743,945	716,570
Other noncurrent assets	52,314	47,323
Total Assets	**$ 7,600,652**	**$ 7,317,783**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 3,338	$ 3,098
Current portion of long-term debt	99,950	144,525
Accounts payable	124,340	201,498
Accrued expenses	246,167	250,579
Regulatory liabilities	61,103	21,145
Total current liabilities	**534,898**	**620,845**
Long-term finance leases	5,461	8,799
Long-term debt	2,684,635	2,474,357
Deferred income taxes	600,520	538,983
Noncurrent regulatory liabilities	657,452	654,213
Other noncurrent liabilities	332,372	355,403
Total Liabilities	**4,815,338**	**4,652,600**
Commitments and Contingencies (Note 18)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 64,761,919 and 61,248,800, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	648	633
Treasury stock at cost	(97,926)	(98,392)
Paid-in capital	2,078,753	1,999,376
Retained earnings	811,495	771,414
Accumulated other comprehensive loss	(7,656)	(7,848)
Total Shareholders' Equity	**2,785,314**	**2,665,183**
Total Liabilities and Shareholders' Equity	**$ 7,600,652**	**$ 7,317,783**

See Notes to Consolidated Financial Statements

NORTHWESTERN ENERGY GROUP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2023	**2022**	**2021**
OPERATING ACTIVITIES:			
Net Income	$ 194,131	$ 183,008	$ 186,840
Items not affecting cash:			
Depreciation and depletion	210,474	195,020	187,467
Amortization of debt issuance costs, discount and deferred hedge gain	5,142	5,321	5,250
Stock-based compensation costs	5,176	5,488	5,350
Equity portion of AFUDC	(17,614)	(14,191)	(11,092)
Loss (gain) on disposition of assets	316	482	(47)
Deferred income taxes	6,584	(8,992)	525
Changes in current assets and liabilities:			
Accounts receivable	32,695	(46,282)	(30,442)
Inventories	(7,180)	(26,744)	(19,604)
Other current assets	2,644	(3,833)	(6,835)
Accounts payable	(54,722)	50,537	7,494
Accrued expenses	(3,377)	16,846	26,055
Regulatory assets	105,588	(20,512)	(69,616)
Regulatory liabilities	39,957	(7,034)	(27,674)
Other noncurrent assets and liabilities	(30,583)	(21,872)	(33,693)
Cash Provided by Operating Activities	489,231	307,242	219,978
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(566,889)	(515,140)	(434,328)
Investment in equity securities	(3,923)	(1,719)	(1,505)
Cash Used in Investing Activities	(570,812)	(516,859)	(435,833)
FINANCING ACTIVITIES:			
Dividends on common stock	(154,050)	(140,062)	(128,483)
Proceeds from issuance of common stock, net	73,613	276,971	196,246
Issuance of long-term debt	300,000	—	99,915
Repayments on long-term debt	—	—	(955)
Line of credit (repayments) borrowings, net	(132,000)	77,000	151,000
Repayments of short-term borrowings	—	—	(100,000)
Treasury stock activity	1,069	603	707
Financing costs	(4,327)	(1,194)	(909)
Cash Provided by Financing Activities	84,305	213,318	217,521
Net Increase in Cash, Cash Equivalents, and Restricted Cash	2,724	3,701	1,666
Cash, Cash Equivalents, and Restricted Cash, beginning of period	22,463	18,762	17,096
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 25,187**	**$ 22,463**	**$ 18,762**

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, 2020	**54,145**	**3,558**	**$ 541**	**$1,513,787**	**$ (98,075)**	**$ 670,111**	**$ (7,269)**	**$ 2,079,095**
Net income	—	—	—	—	—	186,840	—	186,840
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(57)	(57)
Reclassification of net gains on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(436)	(436)
Stock based compensation	93	17	1	5,298	(971)	—	—	4,328
Issuance of shares	3,368	(29)	34	197,142	798	—	—	197,974
Dividends on common stock ($2.48 per share)	—	—	—	—	—	(128,483)	—	(128,483)
Balance at December 31, 2021	**57,606**	**3,546**	**$ 576**	**$1,716,227**	**$ (98,248)**	**$ 728,468**	**$ (7,310)**	**$ 2,339,713**
Net income	—	—	—	—	—	183,008	—	183,008
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(8)	(8)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	452	452
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	(982)	(982)
Stock based compensation	87	16	—	7,391	(911)	—	—	6,480
Issuance of shares	5,585	(28)	57	275,758	767	—	—	276,582
Dividends on common stock ($2.52 per share)	—	—	—	—	—	(140,062)	—	(140,062)
Balance at December 31, 2022	**63,278**	**3,534**	**$ 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 losses 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**

See Notes to Consolidated Financial Statements

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 775,300 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, 2023, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

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. In this reorganization, shareholders of NW Corp (the predecessor publicly held parent company) became shareholders of NorthWestern Energy Group, maintaining the same number of shares and ownership percentage as held in NW Corp immediately prior to the reorganization. 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. Immediately after consummation of the reorganization, NorthWestern Energy Group had, on a consolidated basis, the same assets, businesses and operations as NW Corp had immediately prior to the consummation of the reorganization. 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. On January 1, 2024, we completed the second and final phase of the holding company reorganization. NW Corp contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NWE Public Service, and then distributed its equity interest in NWE Public Service and certain other subsidiaries to NorthWestern Energy Group, resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group.

(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, uncertain tax position reserves, 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

The Company recognizes 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 $2.8 million and $2.5 million at December 31, 2023 and December 31, 2022, respectively. Receivables include unbilled revenues of $105.1 million and $117.4 million at December 31, 2023 and December 31, 2022, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2023	2022
Materials and supplies	$ 85,876	$ 71,769
Storage gas and fuel	28,663	35,590
Total Inventories	$ 114,539	$ 107,359

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, 2023, 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 8 - 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 6.4%, 6.4%, and 6.6% for Montana for 2023, 2022, and 2021, respectively. This rate averaged 6.4% for South Dakota in each of 2023, 2022, and 2021. AFUDC capitalized totaled $24.3 million, $20.2 million, and $15.9 million for the years ended December 31, 2023, 2022, and 2021, respectively, for Montana and South Dakota 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 2 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 2.8% for 2023, 2022, and 2021.

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,	
	2023	2022
Property taxes	$ 79,252	$ 96,093
Employee compensation, benefits, and withholdings	41,773	44,104
Customer advances	27,656	26,137
Interest	24,775	18,350
Other (none of which is individually significant)	72,711	65,895
Total Accrued Expenses	$ 246,167	$ 250,579

Other Noncurrent Liabilities

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

	December 31,	
	2023	2022
Customer advances	$ 107,470	$ 95,393
Pension and other employee benefits	75,302	84,731
AROs	39,255	39,096
Future QF obligation, net	28,670	49,728
Environmental	21,135	22,662
Other (none of which is individually significant)	60,540	63,793
Total Noncurrent Liabilities	$ 332,372	$ 355,403

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. 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 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,		
	2023	2022	2021
		(in thousands)	
Cash paid (received) for:			
Income taxes	$ (827)	$ 4,707	$ 4,330
Interest	105,238	95,400	87,221
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	42,322	64,758	29,034
New Market Tax Credit (NMTC) debt extinguishment included in other noncurrent assets	—	—	18,169
NMTC debt extinguishment included in property, plant and equipment, net	—	—	6,594
NMTC debt extinguishment included in long-term debt	—	—	1,259

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,		
	2023	2022	2021
Cash and cash equivalents	$ 9,164	$ 8,489	$ 2,820
Restricted cash	16,023	13,974	15,942
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 25,187	$ 22,463	$ 18,762

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

There were no accounting standards adopted in the current year that had a material impact to our financial condition, results of operations, and cash flows. 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) Regulatory Matters

Montana Rate Review

On August 8, 2022, we filed a Montana electric and natural gas rate review with the MPSC under Docket 2022.07.78 requesting an annual increase to electric and natural gas utility rates. On October 27, 2023, the MPSC issued a final order approving the settlement agreement filed April 3, 2023. Final rates, adjusting from interim to settled rates, were effective November 1, 2023. The details of our settlement agreement are set forth below:

Returns, Capital Structure & Revenue Increase Resulting From Approved Settlement Agreement ($ in millions)

	Electric	Natural Gas
Return on Equity (ROE)	9.65%	9.55%
Equity Capital Structure	48.02%	48.02%
Base Rates	$67.4	$14.1
PCCAM(1)	$69.7	n/a
Property Tax (tracker base adjustment)(1)	$14.5	$4.2
Total Revenue Increase Through Approved Settlement Agreement	$151.6	$18.3

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

The approved settlement includes, among other things, agreement on electric and natural gas base revenue increases, allocated cost of service, rate design, updates to the base amount of revenues associated with property taxes and electric supply costs, and regulatory policy issues related to requested changes in regulatory mechanisms.

The approved settlement agreement provides for an update to the PCCAM by adjusting the base costs from $138.7 million to $208.4 million and providing for more timely quarterly recovery of deferred balances instead of annual recovery. It also addresses the potential for future recovery of certain operating costs associated with the Yellowstone County Generating Station and provides for the deferral of incremental operating costs related to our Enhanced Wildfire Mitigation Plan. The settling parties agreed to terminate the pilot decoupling program (Fixed Cost Recovery Mechanism) and that the proposed business technology rider will not be implemented.

South Dakota Electric Rate Review

On June 15, 2023, we filed a South Dakota electric rate review filing (2022 test year) under Docket EL23-016 for an annual increase to electric rates totaling approximately $30.9 million. Our request was based on a rate of return of 7.54 percent, a capital structure including 50.5 percent equity, and rate base of $787.3 million. On January 10, 2024, the SDPUC issued a final order approving the settlement agreement between NorthWestern and SDPUC Staff for an annual increase in base rates of approximately $21.5 million and an authorized rate of return of 6.81 percent. The approved settlement is based on a capital structure of 50.5 percent equity and a rate base of $791.8 million. Final rates were effective January 10, 2024. In addition, NorthWestern was approved a phase in rate plan rider that allows for the recovery of capital investments not yet included in base rates.

(4) 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 management's 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, 2023	December 31, 2022
			(in thousands)	
Flow-through income taxes	12	Plant Lives	$ 553,452	$ 509,038
Pension	14	See Note 14	79,638	87,965
Excess deferred income taxes	12	Plant Lives	51,404	54,364
Employee related benefits	14	See Note 14	21,926	27,920
Deferred financing costs	11	See Note 11	20,028	22,620
Environmental clean-up	18	Undetermined	11,131	10,963
Supply costs		1 Year	7,317	101,096
State & local taxes & fees		1 Year	2,733	15,684
Other		Various	25,942	22,929
Total Regulatory Assets			**$ 773,571**	**$ 852,579**
Removal cost	6	Plant Lives	$ 523,744	$ 502,289
Excess deferred income taxes	12	Plant Lives	136,382	148,989
State & local taxes & fees		1 Year	30,576	2,327
Supply costs		1 Year	19,691	11,536
Gas storage sales		16 years	6,625	7,046
Environmental clean-up		1 Year	—	592
Other		Various	1,537	2,579
Total Regulatory Liabilities			**$ 718,555**	**$ 675,358**

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 12 - Income Taxes for further discussion.

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.

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 18 - 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.

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 7.0 percent in Montana; 7.2 percent and 7.8 percent for electric and natural gas, respectively, in South Dakota; and 8.5 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.

State & Local Taxes & Fees (Montana Property Tax Tracker)

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.

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 6 - 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.

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. As discussed within Note 3 - Regulatory Matters, the approved Montana rate review settlement provides for the deferral of incremental operating costs related to this Enhanced Wildfire Mitigation Plan. As of December 31, 2023, we have deferred $1.6 million of incremental costs as a regulatory asset related to this plan for future recovery.

(5) Property, Plant and Equipment

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

	December 31,	
	2023	2022
	(in thousands)	
Electric Plant	$ 5,462,229	$ 5,205,788
Natural Gas Plant	1,506,943	1,371,045
Plant acquisition adjustment[1]	686,328	686,328
Common and Other Plant	267,132	268,970
Construction work in process	377,241	311,652
Total property, plant and equipment	8,299,873	7,843,783
Less accumulated depreciation	(1,930,688)	(1,880,265)
Less accumulated amortization	(329,384)	(306,038)
Net property, plant and equipment	$ 6,039,801	$ 5,657,480

(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 $5.2 million and $7.2 million as of December 31, 2023 and 2022, respectively, which included $5.0 million and $7.0 million as of December 31, 2023 and 2022, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a finance lease.

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.

On January 16, 2023, we entered into a definitive agreement (Agreement) with Avista Corporation (Avista) to acquire Avista's 15 percent interest in each of Units 3 and 4 at the Colstrip Generating Station, a coal-fired, base-load electric generation facility located in Colstrip, Montana. As noted in the table below, we currently have a 30 percent interest in Unit 4. The Agreement provides that the purchase price will be $0 and that we will acquire Avista's interest effective December 31, 2025, subject to the satisfaction of the closing conditions contained within the agreement. Under the terms of this Agreement, we will be responsible for operating costs starting on January 1, 2026; while Avista will retain responsibility for its 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 decommission and demolition costs associated with the existing facilities that comprise Avista's interest.

The Agreement contains customary representations and warranties, covenants, and indemnification obligations, and the Agreement is subject to customary conditions and approvals, including approval from the FERC. Closing also is conditioned on our ability to enter into a new coal supply agreement for Colstrip by December 31, 2024. Such coal supply agreement must provide a sufficient amount of coal to Colstrip to permit the generation of electric power by the maximum permitted capacity of the interest in Colstrip then held by us during the period from January 1, 2026 through, December 31, 2030.

Either party may terminate the Agreement if any requested regulatory approval is denied or if the closing has not occurred by December 31, 2025 or if any law or order would delay or impair closing.

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, 2023				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 156,696	$ 64,132	$ 52,630	$ 323,793
Accumulated depreciation	44,525	37,178	39,393	127,381
December 31, 2022				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 155,567	$ 63,032	$ 51,796	$ 326,584
Accumulated depreciation	42,884	35,847	38,955	121,830

(6) 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,		
	2023	2022	2021
Liability at January 1,	$ 40,894	$ 40,631	$ 45,355
Accretion expense	1,899	1,853	2,233
Liabilities incurred	—	—	—
Liabilities settled	(1,244)	(4,004)	(2,906)
Revisions to cash flows	(125)	2,414	(4,051)
Liability at December 31,	$ 41,424	$ 40,894	$ 40,631

During the twelve months ended December 31, 2023 our ARO liability decreased $1.2 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, 2023, our ARO liability decreased $0.1 million related to changes in both the timing and amount of retirement cost estimates.

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 4 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2023 and 2022.

(7) Goodwill

We completed our annual goodwill impairment test as of April 1, 2023. We evaluated qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors, and overall financial performance) to determine whether it was more likely than not that the fair value of our reporting units were less than their carrying amounts. Our evaluation of these factors concluded that it was not more likely than not that the fair value of our reporting units was less than their carrying amounts and therefore no further testing was necessary.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2023	2022
Electric	$ 243,558	$ 243,558
Natural gas	114,028	114,028
Total Goodwill	$ 357,586	$ 357,586

(8) 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, 2023 and 2022. 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, 2023	
Interest rate contracts	Interest Expense	$	612

A pre-tax loss of approximately $12.8 million is remaining in AOCL as of December 31, 2023, 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.

(9) 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 8 - 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, 2023	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	$ 14,996	$ —	$ —	$ —	$ 14,996
Rabbi trust investments	17,093	—	—	—	17,093
Total	**$ 32,089**	**$ —**	**$ —**	**$ —**	**$ 32,089**
December 31, 2022					
Restricted cash equivalents	$ 12,990	$ —	$ —	$ —	$ 12,990
Rabbi trust investments	20,895	—	—	—	20,895
Total	**$ 33,885**	**$ —**	**$ —**	**$ —**	**$ 33,885**

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, 2023		December 31, 2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,784,585	$ 2,521,030	$ 2,618,882	$ 2,316,700

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.

(10) Unsecured Credit Facilities

On November 29, 2023, NW Corp amended its existing $425.0 million revolving credit facility (the Amended Facility) to address the holding company reorganization and extended the maturity date of the facility to November 29, 2028. The Amended 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. After the completion of the holding company reorganization on January 1, 2024, NW Corp owns and operates only the Montana regulated utility, and the base capacity of the Amended Facility automatically reduced to $400.0 million.

On October 28, 2022, we entered into a $100.0 million Credit Agreement (the Additional Credit Facility) to supplement our existing $425.0 million revolving credit facility. The Additional Credit Facility has a maturity date of April 28, 2024. The Additional Credit 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. As of December 31, 2023, there were no amounts outstanding under this Additional Credit Facility.

On March 25, 2023, we amended our existing $25.0 million swingline credit facility (the Swingline Facility) to extend the maturity date of the facility from March 27, 2024 to March 27, 2025. The Swingline Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a margin of 90.0 basis points, or (b) a base rate, plus a margin of 12.5 basis points. As of December 31, 2023, there were no amounts outstanding under this Swingline Facility.

On January 2, 2024, NW Corp terminated its $100.0 million Additional Credit Facility. On January 4, 2024, NW Corp terminated its $25.0 million Swingline Facility.

On November 29, 2023, NorthWestern Energy Group and its subsidiary, NWE Public Service, entered into a new $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. Upon the completion of the holding company reorganization on January 1, 2024, this credit facility became effective. 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 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 $0.1 million for the years ended December 31, 2023 and 2022.

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

	2023	2022
Unsecured revolving line of credit, expiring May 2027	$ —	$ 425.0
Unsecured revolving line of credit, expiring November 2028[1]	425.0	—
Unsecured revolving line of credit, expiring April 2024[2]	100.0	100.0
Unsecured revolving line of credit, expiring March 2025[2]	25.0	25.0
	550.0	**550.0**
Amounts outstanding at December 31:		
SOFR borrowings	318.0	450.0
Letters of credit	—	—
	318.0	**450.0**
Net availability as of December 31[3]	**$ 232.0**	**$ 100.0**

(1) Upon the completion of the holding company reorganization on January 1, 2024, the base capacity of this facility decreased to $400.0 million.
(2) NW Corp terminated the $100.0 million Additional Credit Facility on January 2, 2024, and the $25.0 million Swingline Facility on January 4, 2024.
(3) As discussed above, upon the completion of the holding company reorganization on January 1, 2024, our total consolidated base capacity increased to $600.0 million and our net availability increased to $282.0 million.

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. A default on the 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 Montana First Mortgage Bonds. A default on the 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 South Dakota First Mortgage Bonds.

(11) Long-Term Debt and Finance Leases

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

	Due	December 31, 2023	2022
Unsecured Debt:			
Unsecured Revolving Line of Credit	2027	$ —	$ 425,000
Unsecured Revolving Line of Credit	2028	318,000	—
Unsecured Revolving Line of Credit	2024	—	25,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—3.21%	2030	50,000	50,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
South Dakota—5.57%	2033	31,000	—
South Dakota—5.42%	2033	30,000	—
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
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—3.21%	2030	100,000	100,000
Montana—1.00%	2024	100,000	100,000
Montana—5.57%	2033	239,000	—
Pollution control obligations—			
Montana—2.00%	2023	—	144,660
Montana—3.88%	2028	144,660	—
Other Long Term Debt:			
Discount on Notes and Bonds and Debt Issuance Costs, Net	—	(13,075)	(10,778)
Total Long-Term Debt		$ 2,784,585	$ 2,618,882
Less current maturities (including associated debt issuance costs)		(99,950)	(144,525)
Total Long-Term Debt, Net of Current Maturities		$ 2,684,635	$ 2,474,357
Finance Leases:			
Total Finance Leases	Various	$ 8,799	$ 11,897
Less current maturities		(3,338)	(3,098)
Total Long-Term Finance Leases		$ 5,461	$ 8,799

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. These bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets. The South Dakota indenture was transferred from NW Corp to NWE Public Service upon the completion of the holding company reorganization on January 1, 2024.

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

On March 30, 2023, we issued and sold $239.0 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 5.57 percent maturing on March 30, 2033. On this same day, we issued and sold $31.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.57 percent maturing on March 30, 2033. On May 1, 2023, we issued and sold an additional $30 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 5.42 percent maturing on May 1, 2033. These bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes.

On June 29, 2023, the City of Forsyth, Rosebud County, Montana issued $144.7 million principal amount of Pollution Control Revenue Refunding Bonds (2023 Pollution Control Bonds) on our behalf. The 2023 Pollution Control Bonds were issued at a fixed interest rate of 3.88 percent maturing on July 1, 2028. The proceeds of the issuance were loaned to us pursuant to a Loan Agreement and were deposited directly with U.S. Bank Trust Company, National Association, as trustee, for the redemption of the 2.00 percent, $144.7 million City of Forsyth Pollution Control Revenue Refunding Bonds due on August 1, 2023 that had previously been issued on our behalf. Pursuant to the Loan Agreement, we are obligated to make payments in such amounts and at such times as will be sufficient to pay, when due, the principal and interest on the 2023 Pollution Control Bonds. Our obligations under the Loan Agreement are secured by delivery of a like amount of our Montana First Mortgage Bonds, which are secured by our Montana electric and natural gas assets. So long as we are making payments under the Loan Agreement, no payments under these mortgage bonds will be due. The 2023 Pollution Control Bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended.

As of December 31, 2023, 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 $103.3 million in 2024, $303.6 million in 2025, $106.9 million in 2026, and $497.7 million in 2028.

(12) Income Taxes

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

	Year Ended December 31,		
	2023	2022	2021
Federal			
Current	$ 2,925	$ 5,024	$ 722
Deferred	2,929	(5,993)	2,626
Investment tax credits	(129)	(130)	(130)
State			
Current	(1,971)	3,363	2,172
Deferred	3,785	(2,869)	(1,971)
Income Tax Expense (Benefit)	$ 7,539	$ (605)	$ 3,419

Our effective tax rate typically differs from the federal statutory tax rate primarily due to production tax credits and 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 following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,		
	2023	2022	2021
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax, net of federal provisions	0.3	0.3	0.1
Flow-through repairs deductions	(12.9)	(12.4)	(11.5)
Production tax credits	(5.1)	(7.2)	(6.1)
Unregulated Tax Cuts and Jobs Act excess deferred income taxes	(1.7)	—	—
Release of unrecognized tax benefits	(1.6)	—	—
Amortization of excess deferred income taxes	(1.1)	(0.9)	(0.3)
Plant and depreciation of flow through items	3.3	(0.1)	(0.6)
Reduction to previously claimed alternative minimum tax credit	1.6	—	—
Prior year permanent return to accrual adjustments	0.0	(0.8)	0.0
Other, net	(0.1)	(0.2)	(0.8)
Effective tax rate	3.7 %	(0.3)%	1.8 %

The table below 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).

	Year Ended December 31,		
	2023	2022	2021
Income Before Income Taxes	$ 201,670	$ 182,403	$ 190,259
Income tax calculated at federal statutory rate	42,350	38,304	39,954
Permanent or flow through adjustments:			
State income, net of federal provisions	606	562	354
Flow-through repairs deductions	(25,922)	(22,665)	(21,888)
Production tax credits	(10,274)	(13,166)	(11,532)
Unregulated Tax Cuts and Jobs Act excess deferred income taxes	(3,385)	—	—
Release of unrecognized tax benefits	(3,241)	—	—
Amortization of excess deferred income taxes	(2,184)	(1,657)	(635)
Plant and depreciation of flow through items	6,595	(222)	(941)
Reduction to previously claimed alternative minimum tax credit	3,186	—	—
Prior year permanent return to accrual adjustments	45	(1,397)	(12)
Other, net	(237)	(364)	(1,881)
	(34,811)	(38,909)	(36,535)
Income Tax Expense (Benefit)	$ 7,539	$ (605)	$ 3,419

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,	
	2023	2022
NOL carryforward	$ 113,366	—
Production tax credit	94,283	$ 80,097
Customer advances	28,300	25,119
Pension / postretirement benefits	15,131	19,291
Compensation accruals	10,716	10,306
Unbilled revenue	10,604	9,440
Environmental liability	5,760	6,009
Interest rate hedges	3,280	3,372
Reserves and accruals	3,098	4,016
Other, net	2,677	2,595
Deferred Tax Asset	**287,215**	**160,245**
Excess tax depreciation	(660,440)	(449,724)
Flow through depreciation	(120,558)	(106,623)
Goodwill amortization	(88,323)	(86,874)
Regulatory assets and other	(18,414)	(56,007)
Deferred Tax Liability	**(887,735)**	**(699,228)**
Deferred Tax Liability, net	**$ (600,520)**	**$ (538,983)**

As of December 31, 2023, our total federal NOL carryforward was approximately $447.8 million. Our federal NOL carryforward does not expire. Our state NOL carryforward as of December 31, 2023 was approximately $362.1 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, 2023, our total production tax credit carryforward was approximately $94.3 million. If unused, our production tax credit carryforwards will expire as follows: $1.8 million in 2035, $10.9 million in 2036, $11.1 million in 2037, $10.9 million in 2038, $11.5 million in 2039, $13.1 million in 2040, $11.5 million in 2041, $13.2 million in 2042, and $10.4 million in 2043. We believe it is more likely than not that sufficient taxable income will be generated to utilize these production tax credit carryforwards.

Uncertain Tax Positions

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):

	2023	2022	2021
Unrecognized Tax Benefits at January 1	$ 30,330	$ 32,049	$ 33,491
Gross increases - tax positions in prior period	—	—	293
Gross increases - tax positions in current period	—	—	—
Gross decreases - tax positions in current period	(2,256)	(1,719)	(1,735)
Lapse of statute of limitations	—	—	—
Unrecognized Tax Benefits at December 31	$ 28,074	$ 30,330	$ 32,049

Our unrecognized tax benefits include approximately $24.4 million and $27.9 million related to tax positions as of December 31, 2023 and 2022, that if recognized, would impact our annual effective tax rate. 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. In the next twelve months we expect the statute of limitations to expire for certain uncertain tax benefits, which would result in a decrease to our total unrecognized tax benefits of approximately $16.9 million.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2023, we have accrued $4.5 million for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2022, we had $1.4 million accrued for the payment of interest and penalties.

Tax years 2020 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 table above.

(13) 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,								
	2023			2022			2021		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 2	$ —	$ 2	$ (8)	$ —	$ (8)	$ (57)	$ —	$ (57)
Reclassification of net income (loss) on derivative instruments	612	(160)	452	612	(160)	452	614	(162)	452
Postretirement medical liability adjustment	(331)	69	(262)	(1,359)	377	(982)	(585)	149	(436)
Other comprehensive (loss) income	$ 283	$ (91)	$ 192	$ (755)	$ 217	$ (538)	$ (28)	$ (13)	$ (41)

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

	December 31,	
	2023	2022
Foreign currency translation	$ 1,437	$ 1,435
Derivative instruments designated as cash flow hedges	(9,373)	(9,825)
Postretirement medical plans	280	542
Accumulated other comprehensive loss	$ (7,656)	$ (7,848)

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

		December 31, 2023 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		$ (9,825)	$ 542	$ 1,435	$ (7,848)
Other comprehensive income before reclassifications		—	—	2	2
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(262)	—	(262)
Net current-period other comprehensive income (loss)		452	(262)	2	192
Ending Balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)

		December 31, 2022 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		$ (10,277)	$ 1,524	$ 1,443	$ (7,310)
Other comprehensive loss before reclassifications		—	—	(8)	(8)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(982)	—	(982)
Net current-period other comprehensive income (loss)		452	(982)	(8)	(538)
Ending Balance		$ (9,825)	$ 542	$ 1,435	$ (7,848)

(14) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and 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 Corporation plan, the pension plan for our Montana employees is referred to as the NorthWestern Energy 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 4 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation 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		Other Postretirement Benefits	
	December 31,		December 31,	
	2023	2022	2023	2022
Change in benefit obligation:				
Obligation at beginning of period	$ 521,798	$ 696,802	$ 15,407	$ 17,308
Service cost	5,646	10,223	333	351
Interest cost	25,852	18,787	674	358
Actuarial loss	3,127	(176,389)	(1,240)	(99)
Settlements[1]	(51,942)	—	—	—
Benefits paid	(30,493)	(27,625)	(1,466)	(2,511)
Benefit Obligation at End of Period	$ 473,988	$ 521,798	$ 13,708	$ 15,407
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 441,539	$ 605,499	$ 20,055	$ 25,289
Return on plan assets	34,367	(144,535)	3,334	(4,098)
Employer contributions	9,200	8,200	386	1,375
Settlements[1]	(51,942)	—	—	—
Benefits paid	(30,493)	(27,625)	(1,466)	(2,511)
Fair value of plan assets at end of period	$ 402,671	$ 441,539	$ 22,309	$ 20,055
Funded Status	$ (71,317)	$ (80,259)	$ 8,601	$ 4,648
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	7,875	7,195	12,378	8,831
Total Assets	7,875	7,195	12,378	8,831
Current liability	(11,200)	(11,200)	(1,355)	(1,585)
Noncurrent liability	(67,992)	(76,254)	(2,422)	(2,598)
Total Liabilities	(79,192)	(87,454)	(3,777)	(4,183)
Net amount recognized	$ (71,317)	$ (80,259)	$ 8,601	$ 4,648
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	—	(116)
Net actuarial (loss) gain	(44,453)	(54,383)	15	(3,123)
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	—	—
Net actuarial gain	—	—	590	1,046
Total	$ (44,453)	$ (54,383)	$ 605	$ (2,193)

(1) In October 2023, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to 285 NorthWestern Energy Pension Plan participants. We purchased the contract with $51.9 million of plan assets. The insurance company took over the payments of these benefits starting January 1, 2024. This transaction settled $51.9 million of our NorthWestern Energy Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2023, we recorded a non-cash, non-operating settlement charge of $4.4 million. This charge is recorded within other income, net on the Consolidated Statements of Income. As discussed within Note 4 – 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 primarily due to the change in discount rate assumption and actual asset returns compared with expected amounts. The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy Pension Plan	
	December 31,	
	2023	2022
Projected benefit obligation	$ 427.3	$ 474.9
Accumulated benefit obligation	427.3	474.9
Fair value of plan assets	348.1	388.7

As of December 31, 2023, the fair value of the NorthWestern Corporation pension plan assets exceed 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,		
	2023	2022	2021	2023	2022	2021
Components of Net Periodic Benefit Cost						
Service cost	$ 5,646	$ 10,223	$ 12,994	$ 333	$ 351	$ 407
Interest cost	25,852	18,787	18,759	674	359	327
Expected return on plan assets	(25,932)	(24,173)	(27,061)	(1,096)	(1,047)	(919)
Amortization of prior service cost (credit)	—	—	—	116	(1,891)	(1,835)
Recognized actuarial loss (gain)	228	383	6,536	(672)	(897)	(898)
Settlement loss recognized(1)	4,395	—	11,291	—	—	—
Net Periodic Benefit Cost (Credit)	$ 10,189	$ 5,220	$ 22,519	$ (645)	$ (3,125)	$ (2,918)
Regulatory deferral of net periodic benefit cost(2)	(1,814)	2,307	(13,308)	—	—	—
Previously deferred costs recognized(2)	210	—	—	550	292	709
Net Periodic Benefit Cost Recognized	$ 8,585	$ 7,527	$ 9,211	$ (95)	$ (2,833)	$ (2,209)

(1) Settlement losses are related to partial annuitization of NorthWestern Energy Pension Plan effective October 24, 2023 and December 1, 2021, respectively.
(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, 2023, 2022, and 2021, 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, 2023 and 2022. 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. The decrease in the discount rate during 2023 increased our projected benefit obligation by approximately $10.5 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 rate of return on assets assumption for NorthWestern Energy Pension Plan to 6.65 percent and increased our assumption on the NorthWestern Corporation Pension Plan to 5.15 percent for 2024.

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

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2023	2022	2021	2023	2022	2021
Discount rate	4.95-5.00 %	5.20	2.65-2.75 %	4.85-4.90 %	5.15-5.20 %	2.35-2.40 %
Expected rate of return on assets	4.83-6.44	2.66-4.26	3.01-4.17	5.62	4.23	4.08
Long-term rate of increase in compensation levels (non-union)	4.00	4.00	2.84	4.00	4.00	2.84
Long-term rate of increase in compensation levels (union)	4.00	4.00	2.00	4.00	4.00	2.00
Interest crediting rate	3.30-6.00	3.30-6.00	3.30-6.00	N/A	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00 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 that a moderate allocation to each can potentially improve the expected risk-adjusted return for the NorthWestern Energy 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 allocation established, within an allowable range of plus or minus 5 percent, is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2023	2022	2023	2022	2023	2022
Fixed income securities	45.0 %	45.0 %	90.0 %	90.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	—	—	—	1.0	—	—
Opportunistic fixed income	11.0	5.5	3.0	—	—	—
Global equities	38.5	44.0	7.0	9.0	60.0	60.0
Private real estate	5.5	5.5	—	—	—	—

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2023	2022	2023	2022	2023	2022
Cash and cash equivalents	— %	— %	1.5 %	1.1 %	0.2 %	0.6 %
Fixed income securities	45.3	44.5	88.7	88.6	35.1	36.7
Non-U.S. fixed income securities	—	—	—	0.9	—	—
Opportunistic fixed income	10.6	5.5	2.9	—	—	—
Global equities	37.6	43.4	6.9	9.4	64.7	62.7
Private real estate	6.5	6.6	—	—	—	—
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. The guidelines allow for a transition to targets over time as assets are reallocated to newly-approved asset classes of opportunistic fixed income and private real estate. 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.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value 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 funds do not contain any redemption restrictions. 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.

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 2024 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 2023, 2022 and 2021 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2023	2022	2021
NorthWestern Energy Pension Plan (MT)	$ 8,000	$ 7,000	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200	1,200
	$ 9,200	$ 8,200	$ 10,200

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2024	27,553	2,149
2025	28,987	1,813
2026	29,920	1,406
2027	30,545	1,251
2028	31,231	1,210
2029-2033	164,362	5,288

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 be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the years ended December 31, 2023, 2022 and 2021 were $13.2 million, $12.3 million, and $11.8 million, respectively.

(15) 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, 2023, there were 649,884 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to four 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 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 will vary from 0 percent to 200 percent of the target award, depending on actual company performance relative to the performance goals. Beginning in 2023, 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. Performance unit awards issued prior to 2023 included both the market- and performance-based components discussed above.

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:

	2023	2022
Risk-free interest rate	4.33 %	1.82 %
Expected life, in years	3	3
Expected volatility	30.4% to 41.0%	28.2% to 38.8%
Dividend yield	4.4 %	4.5 %

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, 2023, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	194,407	$ 51.04
Granted	95,853	54.41
Vested	(87,300)	50.53
Forfeited	(49,176)	51.59
Remaining nonvested grants	153,784	$ 53.26

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, 2023. 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, 2023, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	99,285	$ 48.62
Granted	—	—
Vested	—	—
Forfeited	(38,506)	49.73
Remaining nonvested grants	60,779	$ 47.91

We recognized total stock-based compensation expense of $3.6 million, $4.2 million, and $3.9 million for the years ended December 31, 2023, 2022, and 2021, respectively, and related income tax benefit of $(1.0) million, $(1.3) million, and $(0.2) million for the years ended December 31, 2023, 2022, and 2021, respectively. As of December 31, 2023, we had $6.5 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 $4.4 million, $4.3 million, and $4.2 million for the years ended December 31, 2023, 2022 and 2021, respectively.

(16) 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, 2,865,957 shares are reserved for the incentive plan awards. For further detail of grants under this plan see Note 15 - 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 4,167 and 16,120 during the years ended December 31, 2023 and 2022, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

Issuance of Common Stock

In April 2021, NW Corp entered into an Equity Distribution Agreement pursuant to which we could offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program. During the twelve months ended December 31, 2023, NW Corp issued 1,432,738 shares of our common stock under the ATM program at an average price of $52.02, for net proceeds of $73.6 million, which is net of sales commissions and other fees paid of approximately $0.9 million. We have completed the ATM offering program under this Equity Distribution Agreement.

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.

As of December 31, 2023, approximately $920.0 million of NW Corp unrestricted net assets were available for the payment of dividends to NorthWestern Energy Group under our most restrictive dividend restriction.

(17) 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,		
	2023	2022	2021
Basic computation	60,321,481	55,769,156	51,709,229
Dilutive effect of			
Performance and restricted share awards[1]	36,312	26,621	111,940
Forward equity sale[2]	—	496,333	51,057
Diluted computation	60,357,793	56,292,110	51,872,226

(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.
(2) Forward equity shares 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 forward sale agreement.

As of December 31, 2023, there were 25,913 shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations.

(18) 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 $67 to $136 per MWH through 2029. As of December 31, 2023, our estimated gross contractual obligation related to these contracts was approximately $303.1 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $266.5 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,	
	2023	2022
Beginning QF liability	$ 49,728	$ 64,943
Settlements[1]	(24,707)	(20,076)
Interest expense	3,649	4,861
Ending QF liability	$ 28,670	$ 49,728

(1) The primary components of the change in settlement amounts includes (i) a lower periodic adjustment of $4.2 million due to actual price escalation, which was less than previously modeled; and (ii) higher costs of approximately $1.0 million, due to a $0.8 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $1.8 million reduction in costs in the prior period.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2024	$ 74,110	$ 60,706	$ 13,404
2025	60,360	52,950	7,410
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)	$ 303,062	$ 266,493	$ 36,569

(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 $340.0 million, $328.0 million and $286.7 million for the years ended December 31, 2023, 2022, and 2021, respectively. As of December 31, 2023, our commitments under these contracts were $321.9 million in 2024, $244.1 million in 2025, $263.4 million in 2026, $243.6 million in 2027, $225.9 million in 2028, and $1.5 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 $22.4 million between 2024 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 $21.0 million to $31.4 million. As of December 31, 2023, we had a reserve of approximately $25.3 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,		
	2023	2022	2021
Liability at January 1,	$ 26,367	$ 26,866	$ 28,895
Deductions	(2,520)	(2,033)	(2,799)
Charged to costs and expense	1,439	1,534	770
Liability at December 31,	$ 25,286	$ 26,367	$ 26,866

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

Manufactured Gas Plants - Approximately $19.8 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, 2023, the reserve for remediation costs at this site was approximately $8.0 million, and we estimate that approximately $2.9 million of this amount will be incurred through 2028.

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, and Helena, 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 are awaiting its review and comments as to any additional field work. We now expect the MDEQ review of the RI Report to be concluded in 2024, and any additional field work to commence following that.

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.

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.

Proposed 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. In May 2023, EPA proposed new GHG emissions standards for coal and natural gas-fired plants. In particular, the proposed rules would (i) strengthen the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establish emission guidelines for states to follow in limiting carbon pollution from existing fossil fuel-fired steam generating electric generating units (including coal, oil and natural gas-fired units); and (iii) establish emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired). In addition, in April 2023, EPA proposed to amend the MATS. Among other things, MATS currently sets stringent emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. We are in compliance with existing MATS requirements. The proposed amendment of the MATS would strengthen the MATS requirements, and if adopted as written, both the GHG and MATS proposed rules could have a material negative impact on our coal-fired plants, including requiring potentially expensive upgrades or the early retirement of Colstrip Unit's 3 and 4 due to the rules making the facility uneconomic.

Previous efforts by the EPA were met with extensive litigation and we anticipate a similar response if the proposed rules are adopted. As MATS and GHG regulations are implemented, it could result in additional material compliance costs. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any MATS or GHG regulations that, in our view, disproportionately impact customers in our region.

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

State of Montana - Riverbed Rents

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

The litigation has a long prior history. In 2012, the United States Supreme Court issued a decision holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). On August 1, 2018, the Federal District Court granted our and Talen's motions to dismiss the State's Complaint as it pertains to the navigability of the riverbeds associated with four of our hydroelectric facilities near Great Falls. A bench trial before the Federal District Court commenced January 4, 2022, and concluded on January 18, 2022, which addressed the issue of navigability concerning our other six facilities. On August 25, 2023, the Federal District Court issued its Findings of Fact, Conclusions of Law and Order (the "Order"), which found all but one of the segments of the riverbeds in dispute not navigable, and thus not owned by the State of Montana. The one segment found navigable, and thus owned by the State, was the segment on which the Black Eagle development was located. The State filed a motion to pursue an interlocutory appeal of the Order, and on January 2, 2024, the Federal District Court certified the Order for appeal to the 9th Circuit Court of Appeals. Damages were bifurcated by agreement and will be tried separately for the Black Eagle segment, and any other segments found navigable should an appeal be granted and other segments found navigable.

We dispute the State's claims and intend to continue to vigorously defend the lawsuit. If the Federal District Court calculates damages as the State District Court did in 2008, we do not anticipate the resulting annual rent for the Black Eagle segment would have a material impact to our financial position or results of operations. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

Colstrip Arbitration

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. The six owners of Colstrip Units 3 and 4 currently share the operating costs pursuant to the terms of an Ownership and Operation Agreement (O&O Agreement). However, several of the owners are mandated by Washington and Oregon law to eliminate coal-fired resources in 2025 and 2029, respectively.

As a result of the mandate, the owners have disagreed on various operational funding decisions, including whether closure requires each owner's consent under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), to resolve the issues of whether closure requires each owner's consent and to clarify each owner's obligations to continue to fund operations until all joint owners agree on closure. The owners previously initiated efforts to identify arbitrators and have agreed to stay the Arbitration through March 31, 2024, while they explore a potential resolution to their disagreements.

Colstrip Coal Dust Litigation

On December 14, 2020, a claim was filed against Talen in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. Talen is one of the co-owners of Colstrip Unit 3, and the operator of Units 3 and 4. The plaintiffs allege they have suffered adverse effects from coal dust generated during operations associated with Colstrip. On August 26, 2021, the claim was amended to add in excess of 100 plaintiffs. It also added NorthWestern, the other owners of Colstrip, and Westmoreland Rosebud Mining LLC, as defendants. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties. Since this lawsuit remains in its discovery stages, we are unable to predict outcomes. We continue to evaluate a range of reasonably possible losses.

BNSF Demands for Indemnity and Remediation Costs

NorthWestern has received a demand for indemnity from BNSF Railway Company (BNSF) for past and future environmental investigation and remediation costs incurred by BNSF at one of the three operable units at the Anaconda Copper Mining (ACM) Smelter and Refinery Superfund Site, located near Great Falls, Montana. Smelter and refining operations at the site commenced in 1893 and continued until 1980.

NorthWestern owns property in the Railroad Corridor sub-section of Operable Unit 1. BNSF claims it is entitled to indemnity and contribution from NorthWestern for the costs it has and will incur to investigate and remediate contamination in Operable Unit 1. NorthWestern and BNSF have settled the majority of the dispute for a non-material sum. Any potential remaining claims are not expected to be material.

Yellowstone County Generating Station Air Permit

On October 21, 2021, the Montana Environmental Information Center and the Sierra Club filed a lawsuit in Montana State District Court, against the MDEQ and NorthWestern, alleging that the environmental analysis conducted by MDEQ prior to issuance of the Yellowstone County Generating Station's air quality construction permit was inadequate. On April 4, 2023, the Montana District Court issued an order finding MDEQ's environmental analysis was deficient in not addressing exterior lighting and greenhouse gases and remanded it back to MDEQ to address the deficiencies and vacated the air quality permit pending that remand. As a result of the vacatur of the permit, we paused construction. On June 8, 2023, the Montana District Court granted our motion to stay the order vacating the air quality permit pending the outcome of our notice of appeal with the Montana Supreme Court. Oral argument is scheduled for April 22, 2024 and a determination of the appeal will follow. We recommenced construction in June 2023 and expect the plant to be operational no later than the end of the third quarter 2024. The ultimate resolution of the lawsuit challenging the Yellowstone County Generating Station air quality permit could delay the project and increase costs.

During the litigation of the air permit, Montana House Bill 971 was signed into law, preventing the MDEQ from, except under certain exceptions, evaluating greenhouse gas emissions and corresponding impacts to the climate in environmental reviews of large projects such as coal mines and power plants. On June 1, 2023, the MDEQ issued its supplemental environmental assessment that contained the updated exterior lighting analysis, and the MDEQ indicated that no other analysis was necessary. The comment period concerning the MDEQ’s supplemental air quality permit ended on July 3, 2023. On August 4, 2023, the Montana First Judicial District Court in Held v. State of Montana, a separate case by Montana youths alleging climate damages, issued its order finding House Bill 971 unconstitutional delaying the issuance of the revised Yellowstone County Generating Station's air permit. The Montana Supreme Court granted NorthWestern permission to participate in the Held appeal. The outcome of the Held case could pose additional delays and costs for the Yellowstone County Generating Station.

Other Legal Proceedings

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

(19) 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 millions):

December 31, 2023	**Electric**	**Natural Gas**	**Total**
Montana	408.3	136.1	544.4
South Dakota	67.9	36.6	104.5
Nebraska	—	35.6	35.6
Residential	**476.2**	**208.3**	**684.5**
Montana	431.4	73.7	505.1
South Dakota	103.2	25.9	129.1
Nebraska	—	22.1	22.1
Commercial	**534.6**	**121.7**	**656.3**
Industrial	46.0	1.4	47.4
Lighting, governmental, irrigation, and interdepartmental	32.7	1.7	34.4
Total Customer Revenues	**1,089.5**	**333.1**	**1,422.6**
Other tariff and contract based revenues	86.9	45.3	132.2
Total Revenue from Contracts with Customers	**1,176.4**	**378.4**	**1,554.8**
Regulatory amortization and other	(107.6)	(25.1)	(132.7)
Total Revenues	**$ 1,068.8**	**$ 353.3**	**$ 1,422.1**

December 31, 2022	Electric	Natural Gas	Total
Montana	357.4	152.3	509.7
South Dakota	69.8	39.2	109.0
Nebraska	—	35.8	35.8
Residential	**427.2**	**227.3**	**654.5**
Montana	368.6	79.3	447.9
South Dakota	108.2	28.5	136.7
Nebraska	—	22.1	22.1
Commercial	**476.8**	**129.9**	**606.7**
Industrial	39.8	1.5	41.3
Lighting, governmental, irrigation, and interdepartmental	31.0	1.9	32.9
Total Customer Revenues	**974.8**	**360.6**	**1,335.4**
Other Tariff and Contract Based Revenues	85.7	38.3	124.0
Total Revenue from Contracts with Customers	**1,060.5**	**398.9**	**1,459.4**
Regulatory amortization and other	46.1	(27.7)	18.4
Total Revenues	**$ 1,106.6**	**$ 371.2**	**$ 1,477.8**

December 31, 2021	Electric	Natural Gas	Total
Montana	334.6	126.0	460.6
South Dakota	65.4	26.6	92.0
Nebraska	—	21.0	21.0
Residential	**400.0**	**173.6**	**573.6**
Montana	356.7	64.7	421.4
South Dakota	102.5	19.1	121.6
Nebraska	—	11.4	11.4
Commercial	**459.2**	**95.2**	**554.4**
Industrial	37.9	1.1	39.0
Lighting, governmental, irrigation, and interdepartmental	32.1	1.4	33.5
Total Customer Revenues	**929.2**	**271.3**	**1,200.5**
Other Tariff and Contract Based Revenues	89.5	36.8	126.3
Total Revenue from Contracts with Customers	**1,018.7**	**308.1**	**1,326.8**
Regulatory amortization and other	33.5	12.0	45.5
Total Revenues	**$ 1,052.2**	**$ 320.1**	**$ 1,372.3**

(20) Segment and Related Information

Our reportable business segments are primarily engaged in the electric and natural gas utility businesses. The remainder of our business activities are presented as other, which primarily consists of unallocated corporate costs and some limited unregulated activity within the energy industry.

We evaluate the performance of these segments based on utility margin. The accounting policies of the operating segments are the same as the parent except that the parent allocates some of its operating expenses to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions.

Financial data for the business segments for the twelve months ended are as follows (in thousands):

December 31, 2023	Electric	Gas	Other	Eliminations	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
Utility Margin	806,078	195,803	—	—	1,001,881
Operating and maintenance	166,028	54,496	—	—	220,524
Administrative and general	83,521	32,657	1,182	—	117,360
Property and other taxes	120,289	34,323	(1,544)	—	153,068
Depreciation and depletion	174,071	36,403	—	—	210,474
Operating income	262,169	37,924	362	—	300,455
Interest expense, net	(84,089)	(15,719)	(14,809)	—	(114,617)
Other income, net	11,580	3,344	908	—	15,832
Income tax (expense) benefit	(14,196)	4,627	2,030	—	(7,539)
Net income (loss)	$ 175,464	$ 30,176	$ (11,509)	$ —	$ 194,131
Total assets	$ 6,071,021	$ 1,512,135	$ 17,496	$ —	$ 7,600,652
Capital expenditures	$ 431,547	$ 135,342	$ —	$ —	$ 566,889

December 31, 2022	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,106,565	$ 371,272	$ —	$ —	$ 1,477,837
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	324,434	167,577	—	—	492,011
Utility margin	782,131	203,695	—	—	985,826
Operating and maintenance	167,798	53,629	—	—	221,427
Administrative and general	82,405	31,002	369	—	113,776
Property and other taxes	149,781	42,734	9	—	192,524
Depreciation and depletion	162,404	32,616	—	—	195,020
Operating income (loss)	219,743	43,714	(378)	—	263,079
Interest expense, net	(74,420)	(13,030)	(12,660)	—	(100,110)
Other income, net	12,491	6,399	544	—	19,434
Income tax benefit (expense)	798	(3,108)	2,915	—	605
Net income (loss)	$ 158,612	$ 33,975	$ (9,579)	$ —	$ 183,008
Total assets	$ 5,892,508	$ 1,418,059	$ 7,216	$ —	$ 7,317,783
Capital expenditures	$ 409,707	$ 105,433	$ —	$ —	$ 515,140

December 31, 2021	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,052,182	$ 320,134	$ —	$ —	$ 1,372,316
Fuel, purchased supply and direct transmission expense (exclusive of depreciation and depletion shown separately below)	294,820	130,728	—	—	425,548
Utility margin	757,362	189,406	—	—	946,768
Operating and maintenance	156,383	51,920	—	—	208,303
Administrative and general	72,641	27,550	1,682	—	101,873
Property and other taxes	134,910	38,526	8	—	173,444
Depreciation and depletion	154,626	32,841	—	—	187,467
Operating income	238,802	38,569	(1,690)	—	275,681
Interest expense, net	(82,678)	(6,083)	(4,913)	—	(93,674)
Other income, net	3,676	3,046	1,530	—	8,252
Income tax (expense) benefit	(2,512)	(2,640)	1,733	—	(3,419)
Net income (loss)	$ 157,288	$ 32,892	$ (3,340)	$ —	$ 186,840
Total assets	$ 5,432,578	$ 1,342,031	$ 5,834	$ —	$ 6,780,443
Capital expenditures	$ 354,775	$ 79,553	$ —	$ —	$ 434,328

(21) 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,	
	2023	2022
Operating revenues	$ 356,009	$ 425,283
Operating income	103,163	83,228
Net income	$ 83,142	$ 66,743
Average common shares outstanding	61,244	58,345
Income per average common share:		
Basic	$ 1.37	$ 1.16
Diluted	$ 1.37	$ 1.16

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, 2023
Operating Expenses:	
Administrative and general	$ 231
Total Operating Expenses	231
Operating Loss	231
Earnings from investments in subsidiaries, net of tax	83,142
Other income, net	230
Income before income taxes	83,141
Income tax (expense)	—
Net Income	83,141
Other comprehensive income from subsidiaries, net of tax	365
Comprehensive Income	$ 83,506

See Notes to Condensed Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED BALANCE SHEET

(PARENT COMPANY ONLY)

(in thousands)

	As of December 31, 2023
ASSETS:	
Current Assets:	
Cash and cash equivalents	$ 59
Accounts receivable	207
Total current assets	**266**
Investments in subsidiaries	2,784,924
Other noncurrent assets	4,063
Total Assets	**$ 2,789,253**
LIABILITIES AND SHAREHOLDERS EQUITY	
Other noncurrent liabilities	$ 3,939
Total Liabilities	**3,939**
Total Shareholders' Equity	**2,785,314**
Total Liabilities and Shareholders' Equity	**$ 2,789,253**

See Notes to Condensed Financial Statements

NORTHWESTERN ENERGY GROUP

CONDENSED STATEMENTS OF CASH FLOWS

(PARENT COMPANY ONLY)

(in thousands)

	Year Ended December 31,
	2023
OPERATING ACTIVITIES:	
Net Income	$ 83,141
Adjustments to reconcile net income to cash used in operations:	
Equity in earnings from subsidiaries, net of tax	(83,142)
Cash dividends received from subsidiaries	39,042
Changes in assets and liabilities	
Accounts receivable	(207)
Cash Provided by Operating Activities	38,834
INVESTING ACTIVITIES:	
Contributions to subsidiaries	—
Return of capital from subsidiaries	—
Cash Provided by Investing Activities	—
FINANCING ACTIVITIES:	
Treasury stock activity	351
Dividends on common stock	(39,002)
Financing costs	(124)
Cash Used in Financing Activities	(38,775)
Net Increase in Cash and Cash Equivalents	59
Cash, Cash Equivalents and Restricted Cash, beginning of period	—
Cash and Cash Equivalents end of period	$ 59

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 $39.0 million of cash dividends paid to NorthWestern Energy Group from wholly-owned subsidiaries for the year ended December 31, 2023.