UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025

OR

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

For the transition period from ________________ to ___________________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
001-09057	WEC ENERGY GROUP, INC. (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 1331 Milwaukee, WI 53201 (414) 221-2345	39-1391525

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, $.01 Par Value	WEC	New York Stock Exchange

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 such shorter period that the registrant was required to submit such files).

Yes ☒ No ☐

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant 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 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 Exchange Act).

Yes ☐ No ☒

The aggregate market value of the common stock of WEC Energy Group, Inc. held by non-affiliates was $33.5 billion based upon the reported closing price of such securities as of June 30, 2025.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2026):

Common Stock, $.01 par value, 325,531,361 shares outstanding

<u>Documents incorporated by reference</u>:

Portions of WEC Energy Group, Inc.'s Definitive Proxy Statement on Schedule 14A for its Annual Meeting of Shareholders, to be held on May 7, 2026, are incorporated by reference into Part III hereof.

WEC ENERGY GROUP, INC.
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2025
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GLOSSARY OF TERMS AND ABBREVIATIONS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

Subsidiaries and Affiliates

ATC	American Transmission Company LLC
ATC Holdco	ATC Holdco LLC
ATC Holding	ATC Holding LLC
Bishop Hill III	Bishop Hill Energy III LLC
Blooming Grove	Blooming Grove Wind Energy Center LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Bluewater Gas Storage	Bluewater Gas Storage, LLC
Coyote Ridge	Coyote Ridge Wind, LLC
Delilah I	Delilah Solar Energy LLC
Hardin III	Hardin Solar Energy III LLC
Integrys	Integrys Holding, Inc.
Jayhawk	Jayhawk Wind, LLC
Maple Flats	Maple Flats Solar Energy Center LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
Samson I	Samson Solar Energy LLC
Sapphire Sky	Sapphire Sky Wind Energy LLC
Tatanka Ridge	Tatanka Ridge Wind, LLC
Thunderhead	Thunderhead Wind Energy LLC
UMERC	Upper Michigan Energy Resources Corporation
Upstream	Upstream Wind Energy LLC
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WEC Energy Group	WEC Energy Group, Inc.
WECC	Wisconsin Energy Capital Corporation
WECI	WEC Infrastructure LLC
WECI Energy Holding III	WEC Infrastructure Energy Holding III LLC
WECI Wind Holding I	WEC Infrastructure Wind Holding I LLC
WECI Wind Holding II	WEC Infrastructure Wind Holding II LLC
WEPCo Environmental Trust	WEPCo Environmental Trust Finance I, LLC
WG	Wisconsin Gas LLC
Wispark	Wispark LLC
Wisvest	Wisvest LLC
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies

CBP	United States Customs and Border Protection Agency
DOC	United States Department of Commerce
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
PSCW	Public Service Commission of Wisconsin

SEC	Securities and Exchange Commission
USITC	United States International Trade Commission
WDNR	Wisconsin Department of Natural Resources

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
LIFO	Last-In, First-Out
OPEB	Other Postretirement Employee Benefits
VIE	Variable Interest Entity

Environmental Terms

Act 141	2005 Wisconsin Act 141
BTA	Best Technology Available
CAA	Clean Air Act
CCR	Coal Combustion Residual
CO_2	Carbon Dioxide
ELG	Steam Electric Effluent Limitation Guidelines
GHG	Greenhouse Gas
GHG Power Plant Rule	2024 Greenhouse Gas Power Plant Rule
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxide
PCB	Polychlorinated Biphenyl
PCCC	Permanent Cessation of Coal Combustion
PM2.5	Particulates Less Than 2.5 Micrometers in Diameter
SO_2	Sulfur Dioxide
ZLD	Zero Liquid Discharge

Measurements

Bcf	Billion Cubic Feet
Dth	Dekatherm
GW	Gigawatt
lb/MMBtu	Pound Per Million British Thermal Unit
MDth	One Thousand Dekatherms
MW	Megawatt
MWh	Megawatt-hour
µg/m3	Micrograms Per Cubic Meter

Other Terms and Abbreviations

2007 Junior Notes	WEC Energy Group, Inc.'s 2007 Junior Subordinated Notes Due 2067
2024A Junior Notes	WEC Energy Group, Inc.'s Series 2024A 6.69% Fixed-to-Fixed Reset Rate Junior Subordinated Notes Due June 15, 2055
2024B Junior Notes	WEC Energy Group, Inc.'s Series 2024B 6.74% Fixed-to-Fixed Reset Rate Junior Subordinated Notes Due June 15, 2055
2025 Junior Notes	WEC Energy Group, Inc.'s Series 2025 5.625% Fixed-to-Fixed Reset Rate Junior Subordinated Notes Due May 15, 2056
2027 Notes	WEC Energy Group, Inc.'s 4.375% Convertible Senior Notes Due 2027
2028 Notes	WEC Energy Group, Inc.'s 3.375% Convertible Senior Notes Due 2028
2029 Notes	WEC Energy Group, Inc.'s 4.375% Convertible Senior Notes Due 2029
AD	Antidumping
AI	Artificial Intelligence

AOC	Audit and Oversight Committee of the Board of Directors
AREP	Amended Renewable Energy Plan
ARR	Auction Revenue Right
Badger Hollow I	Badger Hollow Solar Park I
Badger Hollow II	Badger Hollow Solar Park II
BESS	Battery Energy Storage System
CABO	Clean and Affordable Buildings Ordinance
CAO	Chief Administrative Officer
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
Chicago, IL-IN-WI	Chicago, Illinois, Indiana, and Wisconsin
CODM	Chief Operating Decision Maker
Columbia	Columbia Energy Center
Compensation Committee	Compensation Committee of the Board of Directors
CSIRT	Cybersecurity Incident Response Team
CT	Combustion Turbine
CVD	Countervailing Duty
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
Darien	Darien Solar Park
DER	Distributed Energy Resource
EDA	Equity Distribution Agreement
Edgewater	Edgewater Generating Station
Enterprise Security Director	Director of Enterprise Security & Compliance
EPS	Earnings Per Share
ERGS	Elm Road Generating Station
ER 1	Elm Road Generating Station Unit 1
ER 2	Elm Road Generating Station Unit 2
ERSC	Enterprise Risk Steering Committee
ETB	Environmental Trust Bond
Exchange Act	Securities Exchange Act of 1934, as amended
Forward Wind	Forward Wind Energy Center
FTR	Financial Transmission Right
GCRM	Gas Cost Recovery Mechanism
High Noon	High Noon Solar Energy Center
Holding Company Act	Wisconsin Utility Holding Company Act
IRA	Inflation Reduction Act
IT/OT	Information Technology and Operational Technology
ITC	Investment Tax Credit
Koshkonong	Koshkonong Solar Park
LDC	Local Natural Gas Distribution Company
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
MRP	Main Replacement Program
NYMEX	New York Mercantile Exchange
OBBBA	One Big Beautiful Bill Act
OCPP	Oak Creek Power Plant
OMB	Office of Management and Budget
Omnibus Stock Incentive Plan	WEC Energy Group Omnibus Stock Incentive Plan, Amended and Restated, Effective as of May 6, 2021
Paris	Paris Solar-Battery Park
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPP	Presque Isle Power Plant
Point Beach	Point Beach Nuclear Power Plant
PPA	Power Purchase Agreement
PRP	Pipe Retirement Program

PTC	Production Tax Credit
PUHCA 2005	Public Utility Holding Company Act of 2005
Pulliam	J. P. Pulliam Generating Station
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
QIP	Qualifying Infrastructure Plant
REC	Renewable Energy Certificate
Red Barn	Red Barn Wind Park
Renegade	Renegade Solar Energy Center
RICE	Reciprocating Internal Combustion Engine
RNG	Renewable Natural Gas
ROE	Return on Equity
Rothschild	Rothschild Biomass Cogeneration Plant
RTO	Regional Transmission Organization
S&P	Standard & Poor's
Saratoga	Saratoga Solar Electric Generation and BESS Facility
SSR	System Support Resource
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
TCR	Transmission Congestion Right
Tilden	Tilden Mining Company
Two Creeks	Two Creeks Solar Park
UEA	Uncollectible Expense Adjustment
UFLPA	Uyghur Forced Labor Prevention Act
VAPP	Valley Power Plant
VLC	Very Large Customer
West Riverside	West Riverside Energy Center
Weston	Weston Generating Station
Whitetail	Whitetail Wind Energy Generation Facility
Whitewater	Whitewater Cogeneration Facility
WPL	Wisconsin Power and Light Company

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements may be identified by reference to a future period or periods or by the use of terms such as "anticipates," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets," "will," or variations of these terms.

Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of capital projects, sales and customer growth, rate actions and related filings with regulatory authorities, environmental and other regulations, including associated compliance costs, legal proceedings, dividend payout ratios, effective tax rates, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, climate-related matters, our capital plan, liquidity and capital resources, and other matters.

Forward-looking statements are subject to a number of risks and uncertainties that could cause our actual results to differ materially from those expressed or implied in the statements. These risks and uncertainties include those described in Item 1A. Risk Factors and those identified below:

- Factors affecting utility and non-utility energy infrastructure operations such as catastrophic weather-related damage, environmental incidents, unplanned facility outages and repairs and maintenance, electric grid reliability, and electric transmission or natural gas pipeline system constraints;

- Factors affecting the demand for electricity and natural gas, including political or regulatory developments, varying, adverse, or unusually severe weather conditions, changes in economic conditions, including continued economic growth, customer growth and declines, including our ability to develop and/or acquire new generation to meet demand from data centers and other large customers and uncertainty regarding the projected demand from these customers, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers or co-location of generation near data centers;

- The timing, resolution, and impact of rate cases and negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated operations;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, the results of rate orders, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, changes to address energy affordability concerns, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, electrification initiatives and other efforts to reduce the use of natural gas, and tax laws, including those that affect our ability to use PTCs and ITCs, as well as changes in the interpretation and/or enforcement of any laws or regulations by regulatory agencies;

- Federal, state, and local legislative and regulatory changes relating to the environment, including changing environmental regulations impacting generation facilities and renewable energy standards, the enforcement of these laws and regulations, changes in and uncertainty regarding the interpretation of regulations or permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;

- The ability to obtain and retain customers, including wholesale customers, due to increased competition in our electric and natural gas markets from retail choice and alternative electric suppliers, and continued industry consolidation;

- The timely completion of capital projects within budgets and the ability to recover the related costs through rates;

- The impact of changing expectations and demands of our customers, regulators, investors, and other stakeholders;

- The risk of delays and shortages, and increased costs of equipment, materials, or other resources that are critical to our business operations and corporate strategy, as a result of changes to U.S. trade policy (including changes to tariffs on imports, port fees, and other trade policy tools) as well as changes to foreign governments' trade policies impacting U.S. exports, supply chain disruptions (including from rail congestion), inflation, and other factors;

- Risks related to providing service to our data center and other large-scale customers including project termination, cancellation or delay, failure to receive regulatory approvals of projects or tariffs or other necessary permitting or siting approvals, delays in recovery of contractual reimbursement for project costs, the ability to fully recover our investment on assets developed to serve our large-scale customers, lower than anticipated need for electricity by these customers, failure to garner public support, or new legislation or regulation impacting large-scale customer cost allocation;

- The impact of public health crises, including epidemics and pandemics, on our business functions, financial condition, liquidity, and results of operations;

- Risks inherent in electric generation and distribution and natural gas transportation, distribution, and storage activities, including leaks, accidental explosions, mechanical problems, fires, discharges or releases of toxic or hazardous substances or gases, and risks related to the ability to obtain adequate insurance to cover such events;

- Factors affecting the achievement of our CO_2 emission reduction goal and related opportunities and actions, including related regulatory decisions, the cost of materials, supplies, and labor, technology advances, significant increases in demand, the feasibility of competing generation projects, and our ability to execute our capital plan;

- The risks associated with inflation and changing commodity prices, including natural gas and electricity;

- The availability and cost of sources of natural gas and other fossil fuels, purchased power, materials needed to operate environmental controls at our electric generating facilities, or water supply due to high demand, shortages, transportation problems, nonperformance by electric energy or natural gas suppliers under existing power purchase or natural gas supply contracts, or other developments;

- Any impacts on the global economy, including from sanctions, and impacts on supply chains and fuel prices, generally, from increasing tensions between the United States and other countries or from other new, protracted or escalating regional or international conflicts;

- Changes in credit ratings, interest rates, and our ability to access the capital markets, caused by volatility in the global credit markets, our capitalization structure, and market perceptions of the utility industry, us, or any of our subsidiaries;

- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;

- The direct or indirect effect on our business resulting from terrorist or other physical attacks and cybersecurity intrusions, as well as the threat of such incidents, including the failure to maintain the security of personally identifiable information, the associated costs to protect our utility assets, technology systems, and personal information, and the costs to notify affected persons to mitigate their information security concerns and to comply with state notification laws;

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances, that could prevent us from paying our common stock dividends, taxes, and other expenses, and meeting our debt obligations;

- The risk of financial loss, including increases in bad debt expense, associated with the inability of our customers, counterparties, and affiliates to meet their obligations;

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including data center and other large-scale customers, participants in the energy trading markets, and fuel suppliers and transporters;

- The financial performance of ATC and its corresponding contribution to our earnings;

- The investment performance of our employee benefit plan assets, as well as unanticipated changes in related actuarial assumptions, which could impact future funding requirements;

- Factors affecting the employee workforce, including loss of key personnel, internal restructuring, work stoppages, and collective bargaining agreements and negotiations with union employees;

- Advances in technology, and related legislation or regulation supporting the use of that technology, that result in competitive disadvantages and create the potential for impairment of existing assets;

- Risks involved in developing and implementing AI, including data privacy concerns or other legal liability, new or enhanced governmental or regulatory scrutiny or regulations governing the use of AI, the ability to meet expectations or requirements relating to adoption or implementation of AI technology, or other complications related to the use of AI;

- Risks related to our non-utility renewable energy facilities, including unfavorable weather, changes in the financial performance and/or creditworthiness of counterparties to the off-take agreements, changes in demand based on lower prices for alternative energy sources, pricing differentials between the facilities' point of interconnection and our required delivery location, the ability to replace expiring PPAs under acceptable terms, rights to property on which our projects are located but we do not own, the availability of reliable interconnection and electricity grids, the performance and quality of the wind turbine and solar panel components and availability of replacement parts, and exposure to the rules and procedures of the power markets in which these facilities are located;

- The risk associated with the values of goodwill and other long-lived assets, including intangible assets, and equity method investments and their possible impairment;

- Potential business strategies to acquire and dispose of assets or businesses, or portions thereof, which cannot be assured to be completed timely or within budgets, and legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law;

- The timing and outcome of any audits, disputes, and other proceedings related to taxes;

- The effect of accounting pronouncements issued periodically by standard-setting bodies; and

- Other considerations disclosed elsewhere herein and in other reports we file with the SEC or in other publicly disseminated written documents.

Except as may be required by law, we expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

PART I

ITEM 1. BUSINESS

A. INTRODUCTION

In this report, when we refer to "WEC Energy Group," "the Company," "us," "we," "our," or "ours," we are referring to WEC Energy Group, Inc. and all of its subsidiaries. The term "utility" refers to the regulated activities of the electric and natural gas utility companies, while the term "non-utility" refers to the activities of the electric and natural gas companies that are not regulated, as well as We Power and Bluewater. The term "nonregulated" refers to activities at WECI, which holds interests in several renewable generating facilities, WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Wisvest, WECC, WBS, and PDL. References to "Notes" are to the Notes to Consolidated Financial Statements included in this Annual Report on Form 10-K.

For more information about our business operations, including financial and geographic information, see Note 22, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations. For information about our business strategy, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Corporate Developments.

WEC Energy Group, Inc.

We were incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. On June 29, 2015, we acquired 100% of the outstanding common shares of Integrys and changed our name to WEC Energy Group, Inc. Our wholly owned subsidiaries provide or invest in regulated natural gas and electricity, and renewable energy, as well as nonregulated renewable energy. We have an approximately 60% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2025, we had six reportable segments, which are discussed below. For additional information about our reportable segments, see Note 22, Segment Information.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports are made available on our website, www.wecenergygroup.com, free of charge, as soon as reasonably practicable after they are filed with or furnished to the SEC. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at www.sec.gov.

Investors should note that WEC Energy Group announces material financial information in SEC filings, press releases, and public conference calls. In accordance with SEC guidelines, WEC Energy Group also uses the "Investors" tab on its website, www.wecenergygroup.com, to communicate with investors. It is possible that the financial and other information posted there could be deemed material information. The information on WEC Energy Group's website is not part of this document.

B. UTILITY ENERGY OPERATIONS

Wisconsin Segment

The Wisconsin segment includes the electric and natural gas utility operations of WE, WPS, WG, and UMERC.

Electric Utility Operations

Our electric utility operations include the operations of WE, WPS, and UMERC.

- WE generates and distributes electric energy to customers located in southeastern Wisconsin (including the metropolitan Milwaukee area), east central Wisconsin, and northern Wisconsin.
- WPS generates and distributes electric energy to customers located in northeastern and central Wisconsin.

- UMERC generates and distributes electric energy to customers, including one iron ore mine owned by Tilden, located in the Upper Peninsula of Michigan.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2025, 2024, and 2023, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Electric Sales

Our electric energy deliveries included supply and distribution sales to retail, wholesale, and resale customers, and distribution sales to those customers who switched to an alternative electric supplier in the Upper Peninsula of Michigan. In 2025, retail revenues accounted for 92.3% of total electric operating revenues, wholesale revenues accounted for 1.9% of total electric operating revenues, and resale revenues accounted for 4.8% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders for information on MWh sales by customer class.

Our electric utilities are authorized to provide retail electric service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities, and in certain territories in the state of Michigan pursuant to franchises granted by municipalities.

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers.

The majority of our sales for resale are conducted within an energy market operated by MISO at market rates based on the availability of our generation and market demand. Retail fuel costs are reduced by the amount that revenue exceeds the cost of sales derived from these opportunity sales.

Our electric utilities buy and sell electric power by participating in the MISO Energy Markets. The cost of our individual generation offered into the MISO Energy Markets compared to our competitors affects how often our generating units are dispatched and whether we buy or sell power. For more information on the MISO Energy Markets, see E. Regulation.

Steam Sales

WE has a steam utility that generates, distributes, and sells steam supplied by the VAPP to customers in metropolitan Milwaukee, Wisconsin. Steam is used by customers for processing, space heating, domestic hot water, and humidification. Annual sales of steam fluctuate from year to year based on system growth and variations in weather conditions.

Electric Sales Forecast

Our service territory experienced higher weather-normalized retail electric sales in 2025, compared with 2024. We currently forecast retail electric sales volumes, excluding the Tilden mine located in the Upper Peninsula of Michigan, to increase 1.6% for 2026, compared with 2025, assuming normal weather. Excluding the very large data center customers, we currently forecast sales volumes to be relatively flat for 2026, assuming normal weather.

Customers

(in thousands)	Year Ended December 31 2025	2024	2023
Electric customers – end of year			
Residential	**1,512.2**	1,499.4	1,487.9
Small commercial and industrial	**181.9**	180.8	179.0
Large commercial and industrial	**0.8**	0.8	0.8
Wholesale and other	**1.7**	1.7	1.6
Total electric customers – end of year	**1,696.6**	1,682.7	1,669.3
Steam customers – end of year	**0.4**	0.4	0.4

Electric Commercial and Industrial Retail Customers

We provide electric utility service to a diversified base of customers in industries such as metals and other manufacturing, paper, governmental, food manufacturing, and health services.

Electric Generation and Supply Mix

Our electric supply strategy is to provide our customers with energy from a diverse generation portfolio that balances a stable, reliable, and affordable supply of electricity with environmental stewardship. Through our participation in the MISO Energy Markets, we supply a significant amount of electricity to our customers from generation that we own. We supplement our internally generated power supply with long-term PPAs, including the Point Beach PPA discussed under the heading "Power Purchase Commitments," and through spot purchases in the MISO Energy Markets. We also sell excess power supply into the MISO Energy Markets when it is economical, which reduces net fuel costs by offsetting costs of purchased power. On a real time basis, the MISO Energy Market continuously evaluates system load requirements and dispatches the lowest-cost generation resources, while respecting any limitations on the transmission system.

The table below indicates our sources of electric energy supply as a percentage of sales for the three years ended December 31, as well as estimates for 2026:

	Estimate [(1)]	Actual		
	2026	2025	2024	2023
Company-owned generation:				
Coal	30.7 %	**30.5 %**	29.4 %	29.0 %
Natural gas:				
Combined cycle	27.7 %	**24.1 %**	27.2 %	28.7 %
Steam turbine	0.5 %	**0.8 %**	1.0 %	0.9 %
Natural gas/oil peaking units	5.0 %	**7.9 %**	7.2 %	5.5 %
Renewables [(2)]	9.1 %	**8.4 %**	6.5 %	5.5 %
Total company-owned generation	73.0 %	**71.7 %**	71.3 %	69.6 %
Power purchase contracts:				
Nuclear	19.2 %	**19.8 %**	20.3 %	20.1 %
Renewables [(3)]	1.6 %	**1.5 %**	1.9 %	2.0 %
Other	— %	**0.2 %**	— %	0.1 %
Total power purchase contracts	20.8 %	**21.5 %**	22.2 %	22.2 %
Purchased power from MISO	6.2 %	**6.8 %**	6.5 %	8.2 %
Total purchased power	27.0 %	**28.3 %**	28.7 %	30.4 %
Total electric utility supply	100.0 %	**100.0 %**	100.0 %	100.0 %

(1) The values included in the estimate assume a natural gas price based on the December 2025 NYMEX.

(2) Includes hydroelectric, biomass, solar, BESS, and wind generation.

(3) Includes hydroelectric, wind, and customer-owned renewable generation.

Electric Generation Facilities

Our generation portfolio is a mix of energy resources having different operating characteristics and fuel sources. We own 8,375 MWs of generation capacity, including wholly owned and jointly owned facilities. We Power's generating units are also included in the generation capacity. Our generation facilities include natural gas-fired plants, coal-fired plants, renewable generation, and BESSs. Certain of our natural gas-fired generation units have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our facilities, see Item 2. Properties.

We are engaged in discussions with a small number of customers to provide power to large-scale data centers being constructed in our service territories. We anticipate electric demand growth in the years ahead from these VLCs. Subject to pending regulatory approvals from the PSCW as discussed below, WE is planning to make significant infrastructure investments in new natural gas-fired plants, wind, solar and battery projects, and other generation and distribution assets to power and serve these large-scale data centers and other projects. We are working closely with the new data center customers to provide bespoke resources, which are generation resources assigned to the VLCs that match their growing demand in order to minimize the impact on our other retail customers.

Supporting Economic Growth Within Our Communities

Our capital plan reflects the planned retirement of our older, fossil-fueled generation, which we expect to replace with natural gas-fired generation and zero-carbon-emitting renewables. These retirements are intended to address compliance with EPA regulations established under the CAA, as well as contribute to meeting our goal to reduce CO_2 emissions from our electric generation. When taken together, the retirements and new investments in natural gas generation and renewables discussed in more detail below should better balance our supply with our demand, while helping to address compliance and maintaining reliable, affordable energy for our customers. As described in the preceding section, we are planning to make significant investments in generation and distribution assets for the future demands of VLCs.

Environmental Goal

Our long-term goal is to achieve net carbon neutral electric generation by the end of 2050. We expect to achieve this goal by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. We expect to use coal only as a backup fuel by the end of 2030 and to be in a position to eliminate coal as an energy source by the end of 2032. As of the end of 2025, our electric generation fleet has achieved a 53% reduction in carbon emissions from the 2005 baseline.

As part of our path toward this goal, we have started implementing co-firing with natural gas at the ERGS coal-fired units and at Weston Unit 4. Additionally, we have retired nearly 2,500 MWs of fossil-fueled generation since the beginning of 2018, which includes the 2024 retirements of OCPP Units 5 and 6, the 2019 retirement of the PIPP, and the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit. See Note 6, Regulatory Assets and Liabilities, for more information related to certain of these power plant retirements. We expect to retire approximately 900 MWs of additional coal-fired generation by the end of 2031, which includes the planned retirements of OCPP Units 7 and 8 and Weston Unit 3. See Note 7, Property, Plant, and Equipment, for more information.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Corporate Developments for more information on our capital plan.

Also see Item 1A. Risk Factors - Risks Related to Legislation and Regulation - Our operations, capital expenditures, and financial results may be affected by the impact of GHG legislation, regulation, and our emission reduction goal.

Renewable Generation

Our electric utilities meet a portion of their electric generation supply with various renewable energy resources, including wind, solar, hydroelectric, and biomass. This helps our electric utilities work towards our goal of reducing carbon emissions while also maintaining compliance with renewable energy legislation. These renewable energy resources also help us maintain diversity in our generation portfolio, which effectively serves as a price hedge against future fuel costs, and will help mitigate the risk of potential unknown costs associated with any future carbon restrictions for electric generators.

Wind

Our utilities continue to invest in and upgrade their wind-powered generation systems to enhance reliability. We have received approval from the PSCW to acquire and construct 160 MWs of additional wind-powered generation. Our subsidiaries will jointly own these generation facilities with an unaffiliated entity. See Note 8, Jointly-Owned Utility Facilities, for more information.

Solar and Battery Storage

In June 2025, the construction of the battery portion of Paris located in Kenosha County, Wisconsin was completed, and the facility became commercially operational. The solar portion of Paris was commercially operational in December 2024. Paris is owned by WE, WPS, and an unaffiliated entity, with WE and WPS collectively owning 180 MWs of solar generation. WE and WPS also collectively own 99 MWs of battery storage associated with this project.

In March 2025, the construction of the solar portion of Darien located in Rock and Walworth counties, Wisconsin was completed, and the facility became commercially operational. Darien is owned by WE, WPS, and an unaffiliated entity, with WE and WPS collectively owning 225 MWs of solar generation. WE and WPS will collectively own 68 MWs of battery storage associated with this project, with construction expected to be completed in 2027.

As part of our commitment to invest in additional zero-carbon generation within our Wisconsin segment, we have received approval from the PSCW to acquire and construct 955 MWs of additional solar-powered generation and 411 MWs of battery storage. See Note 8, Jointly-Owned Utility Facilities, for more information.

We have also filed requests with the PSCW to acquire and construct 1,333 MWs of solar-powered generation and 212 MWs of battery storage.

Thermal Generation

As part of our commitment to invest in additional thermal generation within our Wisconsin segment, we have received approval from the PSCW to acquire and construct 1,228 MWs of additional natural gas-fired generation.

We have also filed requests with the PSCW to acquire and construct 1,660 MWs of additional natural gas-fired generation. Some of the generation projects pending approval are for bespoke resources to serve VLCs. See Note 26, Regulatory Environment, for more information on bespoke resources and the proposed VLC tariff.

Electric System Reliability

The PSCW requires us to maintain a planning reserve margin above our projected annual peak demand forecast to help ensure reliability of electric service to our customers. These planning reserve requirements are consistent with the MISO calculated planning reserve margin. In 2008, the PSCW established a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO. MISO implemented seasonal requirements effective June 1, 2023. The installed capacity reserve margins for the planning year June 1, 2025 through May 31, 2026 are as follows: 15.7% summer (June – August); 25.3% fall (September – November); 38.6% winter (December – February); and 38.8% spring (March – May). MISO's short-term reserve margin requirements experience year-to-year and season-to-season fluctuations, primarily due to changes in the generation resource mix and average forced outage rate of generation within the MISO footprint.

Michigan legislation requires all electric providers to annually demonstrate to the MPSC that they have adequate resources to serve the anticipated needs of their customers for a minimum of four consecutive planning years beginning in the upcoming planning year June 1, 2026, through May 31, 2027. The MPSC has established future planning reserve margin requirements based on the same study conducted by MISO that determines the short-term reserve margin requirements.

In both our Wisconsin and Michigan jurisdictions, we believe that we have adequate capacity through company-owned generation units and power purchase contracts to meet the MISO calculated planning reserve margin during the current planning year. We also fully anticipate that we will have adequate capacity to meet the planning reserve margin requirements for the upcoming planning year in both jurisdictions.

Fuel and Purchased Power Costs

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules set by the PSCW generally allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs beyond a 2% price variance from the costs included in the rates charged to customers. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers. For more information about the fuel rules, see E. Regulation.

Our average fuel and purchased power costs per MWh by fuel type, including delivery costs, were as follows for the years ended December 31:

	2025	2024	2023
Coal	**$ 27.54**	$ 25.38	$ 25.80
Natural gas combined cycle	**26.49**	20.52	30.41
Natural gas/oil peaking units	**56.82**	42.41	56.41
Biomass	**79.32**	81.33	87.73
Purchased power	**63.06**	57.39	53.90

WE and WPS purchase coal under long-term contracts, which helps with price stability. Coal and associated transportation services are exposed to volatility in pricing due to changing domestic and world-wide demand for coal and diesel fuel. To mitigate against this volatility risk, WE and WPS have PSCW approval for a hedging program. This program allows them to hedge, over a 60-month period, up to 75% of their potential risks related to rail transportation fuel surcharge exposure. The results of this hedging program, when used, are reflected in the average costs of fuel and purchased power.

We purchase natural gas for our plants on the spot market from natural gas marketers, utilities, and producers, and we arrange for transportation of the natural gas to our plants. We have firm and interruptible transportation, as well as balancing and storage agreements, intended to support our plants' variable usage. WE and WPS also have PSCW approval for a hedging program to mitigate against volatility related to natural gas price risk. This program allows them to hedge, over a 60-month period, up to 75% of their estimated natural gas use for electric generation. The results of this hedging program are reflected in the average costs of natural gas.

Coal Supply

We diversify the coal supply for our electric generating facilities and jointly-owned plants by purchasing coal from several mines in Wyoming and Pennsylvania, as well as from various other states. For 2026, 51% of our total projected coal requirements of 8.9 million tons are contracted under fixed-price contracts. See Note 24, Commitments and Contingencies, for more information on amounts of coal purchases and coal deliveries under contract.

The annual tonnage amounts contracted for the next three years are as follows.

(in thousands)	**Annual Tonnage**
2026	4,542
2027	1,125
2028	—

Coal Deliveries

All of our coal requirements are expected to be shipped by unit trains that we own or lease under existing transportation agreements. The unit trains transport the coal for electric generating facilities from mines in Wyoming and Pennsylvania. Additional small volume agreements may also be used to supplement the normal coal supply for our facilities. For additional information concerning risks related to coal supply chain disruptions, see the risk factor below.

- Item 1A. Risk Factors – Risks Related to Economic and Market Volatility – We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

Power Purchase Commitments

We enter into short- and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. Excluding planning capacity purchases, our power purchase commitments with unaffiliated parties consist of 1,133 MWs per year for 2026 through 2029 and 1,033 MWs in 2030. This amount includes 1,033 MWs per year related to a long-term PPA for electricity generated by Point Beach. If necessary, we purchase planning capacity from the MISO annual auction to ensure that we maintain our compliance with planning reserve requirements as established by the PSCW, MPSC, and MISO.

Natural Gas Utility Operations

WE, WPS, and WG are authorized to provide retail natural gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. Our Wisconsin natural gas utilities operate throughout the state of Wisconsin, including the City of Milwaukee and surrounding areas, northeastern Wisconsin, and in large areas of both central and western Wisconsin. In addition, UMERC is authorized to provide retail natural gas distribution service in designated territories in the Upper Peninsula of Michigan.

Our Wisconsin segment natural gas utilities provide service to residential and commercial and industrial customers. In addition, our Wisconsin segment offers natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Major industries served include real estate, food manufacturing, governmental, restaurants, and paper. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders for information on natural gas sales volumes by customer class in Wisconsin and the Upper Peninsula of Michigan.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2025, 2024, and 2023, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Natural Gas Sales Forecast

Our combined Wisconsin service territories experienced slightly lower weather-normalized retail natural gas deliveries (excluding natural gas deliveries for electric generation) in 2025 as compared to 2024. We currently forecast retail natural gas delivery volumes to decrease slightly in 2026 as compared to 2025, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	**2025**	**2024**	**2023**
Customers – end of year			
Residential	**1,404.9**	1,391.7	1,381.7
Commercial and industrial	**136.6**	135.7	134.8
Transportation	**3.5**	3.5	3.5
Total customers	**1,545.0**	1,530.9	1,520.0

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

Pipeline Capacity and Storage

We have long-term firm capacity contracts with interstate pipelines that access supply from a variety of natural gas producing areas. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

Due to variations in natural gas usage in Wisconsin, our Wisconsin natural gas utilities have also contracted for substantial underground storage capacity, primarily in Michigan. WE, WPS, and WG have entered into long-term service agreements for approximately 99% of a wholly owned subsidiary of Bluewater's natural gas storage. Bluewater owns natural gas storage facilities in Michigan and provides approximately one-third of the current storage needs for our Wisconsin natural gas utilities. We target storage inventory levels at approximately 40% of forecasted demand for November through March. Diversity of natural gas supply enables us to manage significant changes in demand and to optimize our overall natural gas supply and capacity costs. We generally inject natural gas into storage during the spring and summer months and withdraw it in the winter months.

We contract with interstate pipeline companies, as well as other service providers, to purchase firm transportation and storage services under varied-length long-term contracts. We believe that having diverse capacity and storage benefits our customers.

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our Wisconsin segment natural gas utilities' forecasted design peak-day throughput is 39.9 million therms for the 2025 through 2026 heating season. Our Wisconsin segment natural gas utilities' peak daily send-out during 2025 was 24.2 million therms on January 20, 2025. Peak or near-peak demand generally occurs only a few times each year. Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. The secondary markets facilitate utilization of capacity and supply during times when the contracted capacity and supply are in excess of utility demand. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. For information on the GCRMs, see Note 1(d), Operating Revenues.

To ensure a reliable supply of natural gas during peak winter conditions, we have LNG facilities located within our distribution system. These facilities are typically utilized during extreme demand conditions to ensure reliable supply to our customers. WE and WG each have LNG facilities, which together provide approximately two Bcf of natural gas supply. The PSCW approved WE's request to construct an additional LNG facility with a storage capacity of two Bcf. The construction of additional LNG facilities in Wisconsin has been proposed as part of the 2026-2030 capital plan and would provide another approximately four Bcf of natural gas supply. The use of LNG allows us to meet anticipated peak demand without requiring the construction of additional interstate pipeline capacity.

Natural Gas Supply

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, storage, peak-shaving facilities, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

Hedging Natural Gas Supply Prices

As part of their hedging programs, our Wisconsin utilities further reduce their supply cost volatility through the use of a mix of financial instruments, such as NYMEX-based natural gas options and futures contracts. WE, WPS, and WG have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand. These approvals allow these companies to pass 100% of the hedging costs (premiums, brokerage fees, and losses) and proceeds (gains) to customers through their respective GCRMs.

Illinois Segment

Our Illinois segment includes the natural gas utility operations of PGL and NSG. Our customers are located in Chicago and the northern suburbs of Chicago. PGL and NSG provide service to residential and commercial and industrial customers. In addition, PGL and NSG offer natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Major industries served include real estate, non-profits, education, restaurants, and wholesale distributors. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Illinois Segment Contribution to Net Income Attributed to Common Shareholders for information on natural gas sales volumes by customer class.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2025, 2024, and 2023, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Customers

	Year Ended December 31		
(in thousands)	2025	2024	2023
Customers – end of year			
Residential	**937.9**	929.0	922.9
Commercial and industrial	**70.9**	71.0	71.3
Transportation	**55.2**	59.9	62.0
Total customers	**1,064.0**	1,059.9	1,056.2

Natural Gas Supply, Pipeline Capacity, and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

Pipeline Capacity and Storage

We have long-term firm capacity contracts with interstate pipelines that access supply from a variety of natural gas producing areas. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

We own a 38.8 Bcf storage field (Manlove Field in central Illinois) and contract with various other underground storage service providers for additional storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, which provides a hedge against supply cost volatility. We also own a natural gas pipeline system that connects Manlove Field to Chicago and nine major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in our regulatory rate base. We also use a portion of these company-owned storage and pipeline assets as a natural gas hub, which consists of providing transportation and storage services in interstate commerce to our wholesale customers. Customers deliver natural gas to us for storage through an injection into the storage reservoir, and we return the natural gas to the customers under an agreed schedule through a withdrawal from the storage reservoir. Title to the natural gas does not transfer to us. We recognize service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our Illinois utilities' forecasted design peak-day throughput is 25.1 million therms for the 2025 through 2026 heating season. Our Illinois utilities' peak daily send-out during 2025 was 19.4 million therms on January 21, 2025. Peak or near-peak demand generally occurs only a few times each year. Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. The secondary markets facilitate utilization of capacity and supply during times when the contracted capacity and supply are in excess of utility demand. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. For information on the GCRMs, see Note 1(d), Operating Revenues.

Natural Gas Supply

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, storage, peak-shaving facilities, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

Hedging Natural Gas Supply Prices

As part of their hedging programs, our Illinois utilities further reduce their supply cost volatility through the use of a mix of financial instruments, such as NYMEX-based natural gas options and futures contracts. Their hedging programs are reviewed by the ICC as part of the annual purchased gas adjustment reconciliation. They hedge between 25% and 50% of planned natural gas purchases, with a target of 37.5%.

Natural Gas Pipe Retirement Program

In February 2025, the ICC issued an order setting expectations for PGL's prospective operations. The ICC directed us to focus on retiring all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. The ICC also indicated that failure to comply with this directive could subject us to civil penalties under Illinois statute. PGL is working to retire this cast and ductile iron pipe through its PRP. Costs incurred under the PRP will be evaluated for prudency by the ICC in future rate cases. In addition, the program will be overseen by a safety monitor hired by the ICC.

For information on regulatory proceedings related to the PRP, see Note 26, Regulatory Environment, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Illinois Proceedings.

Other States Segment

Our other states segment includes the natural gas utility operations of MERC and MGU and the non-utility operations of MERC related to servicing appliances for customers. MERC serves customers in various cities and communities throughout Minnesota, and MGU serves customers in southern and western Michigan. MERC and MGU provide service to residential and commercial and industrial customers. In addition, MERC and MGU offer natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Major industries served include real estate, education, restaurants, wholesale distributors, and non-profits. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Other States Segment Contribution to Net Income Attributed to Common Shareholders for information on natural gas sales volumes by customer class.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2025, 2024, and 2023, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Customers

	Year Ended December 31		
(in thousands)	2025	2024	2023
Customers – end of year			
Residential	**387.1**	383.7	379.3
Commercial and industrial	**37.6**	37.2	36.8
Transportation	**19.4**	19.4	19.5
Total customers	**444.1**	440.3	435.6

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

Pipeline Capacity and Storage

MGU owns a 2.9 Bcf storage field (Partello in Michigan) and contracts with various other underground storage service providers for additional storage services. We contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having diverse capacity and storage benefits our customers.

Combined with our storage capability, management believes that the volume of gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Forecasted design peak-day throughput for our other states utilities is 9.5 million therms for the 2025 through 2026 heating season. Our other states utilities' peak daily send-out during 2025 was 7.9 million therms on January 20, 2025. Peak or near-peak demand generally occurs only a few times each year. Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. The secondary markets facilitate utilization of capacity and supply during times when the contracted capacity and supply are in excess of utility demand. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. For information on the GCRMs, see Note 1(d), Operating Revenues.

Natural Gas Supply

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, contracted and owned storage, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

Hedging Natural Gas Supply Prices

Our other states utilities further reduce their supply cost volatility through the use of financial instruments, such as commodity futures, swaps, and options as part of their hedging programs. MERC has MPUC approval to hedge up to 30% of planned winter demand using NYMEX financial instruments. MGU has MPSC approval to hedge up to 20% of its planned annual purchases using NYMEX financial instruments.

General

Seasonality

Electric Utility Operations – Wisconsin Segment

Our electric utility sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. We continue to upgrade our electric distribution system, including substations, transformers, and lines, to meet the demand of our customers. In 2025, our generating plants performed as expected during the most demanding periods of the year, and all power purchase commitments under firm contract were received. During this period, our electric utilities did not make any public appeals for conservation, and they did not interrupt or curtail service to non-firm customers who participate in load management programs. Our electric utilities did have economic interruption events; however, service to customers was not curtailed. Economic interruptions are declared during times in which the price of electricity in the regional market exceeds the cost of operating the company's peaking generation. During this time, customers taking service under these interruptible programs can choose to continue using electricity at a price based on wholesale market prices or to reduce their load.

Natural Gas Utility Operations – Wisconsin, Illinois, and Other States Segments

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to some variations in earnings and working capital throughout the year as a result of changes in weather. The effect on earnings from these changes in weather are reduced by decoupling mechanisms included in the rates of PGL, NSG, and MERC. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes.

Our natural gas utilities' working capital needs are met by cash generated from operations and debt (both long-term and short-term). The seasonality of natural gas revenues causes the timing of cash collections to be concentrated from January through June. A portion of the winter natural gas supply needs is typically purchased and stored from April through November. Also, planned capital spending on our natural gas distribution facilities is concentrated in April through November. Because of these timing differences, the cash flow from customers is typically supplemented with temporary increases in short-term borrowings (from external sources) during the late summer and fall. Short-term debt is typically reduced over the January through June period.

Competition

Electric Utility Operations – Wisconsin Segment

Our electric utilities face competition from various entities and other forms of energy sources available to customers, including self-generation by customers and alternative energy sources. Our electric utilities compete with other utilities for sales to municipalities and cooperatives as well as with other utilities and marketers for wholesale electric business.

Natural Gas Utility Operations – Wisconsin, Illinois, and Other States Segments

Our natural gas utilities also face varying degrees of competition from other entities and other forms of energy available to consumers. Many large commercial and industrial customers have the ability to switch between natural gas and alternative fuels. Electrification initiatives or mandates are being considered or proposed by local and state governments. In addition, the majority of our natural gas customers have the opportunity to choose a natural gas supplier other than us. Our natural gas utilities offer transportation services for customers that elect to purchase natural gas directly from a third-party supplier. We continue to earn distribution revenues from these transportation customers for their use of our distribution systems to transport natural gas to their facilities. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs.

For more information on electrification initiatives in certain of our Illinois service territories, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters - Chicago Decarbonization Efforts.

For more information on competition in each of our service territories, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Competitive Markets.

Methane Emission Reductions

Natural Gas Utility Operations – Wisconsin, Illinois, and Other States Segments

We continue to focus on methane emission reductions by improving and upgrading our natural gas distribution systems, and using RNG throughout our natural gas utility systems. In 2023, our Wisconsin utilities began transporting the output of local dairy farms onto their natural gas distribution systems. The RNG supplied is replacing higher-emission methane from natural gas that would have entered our pipes. We currently have contracts in place for 2.1 Bcf of RNG.

C. ELECTRIC TRANSMISSION SEGMENT

ATC is a regional transmission company that owns, maintains, monitors, and operates electric transmission systems in Wisconsin, Michigan, Illinois, and Minnesota. ATC is expected to provide comparable service to all customers, including WE, WPS, and UMERC, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by the FERC for all rate terms and conditions of service and certain state regulatory commissions for routing and siting of transmission projects. ATC is also a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and WE, WPS, and UMERC are non-transmission owning members and customers of MISO. As of December 31, 2025, our ownership interest in ATC was approximately 60%. In addition, as of December 31, 2025, we owned approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. See Note 21, Investment in Transmission Affiliates, for more information.

The FERC and D.C. Circuit Court of Appeals have issued orders and an opinion, respectively, related to the authorized base ROE for all MISO transmission owners, including ATC. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – American Transmission Company Allowed Return on Equity Complaints for more information.

D. NON-UTILITY OPERATIONS

Non-Utility Energy Infrastructure Segment

The non-utility energy infrastructure segment includes We Power, which owns and leases generating facilities to WE; Bluewater, which owns underground natural gas storage facilities in Michigan; and WECI, which holds ownership interests in several renewable generating facilities. See Item 2. Properties, for more information on our non-utility energy infrastructure facilities.

W.E. Power, LLC

We Power, through wholly owned subsidiaries, designed and built approximately 2,500 MWs of generation in Wisconsin. This generation is made up of capacity from the two coal-fired ERGS units, ER 1 and ER 2, which were placed in service in February 2010 and January 2011, respectively, and the two natural gas-fired PWGS units, PWGS 1 and PWGS 2, which were placed in service in July 2005 and May 2008, respectively. Two unaffiliated entities collectively own approximately 17%, or approximately 211 MWs, of ER 1 and ER 2. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases (the ERGS units have 30-year leases that began on the in-service dates of the generating units and the PWGS units have 25-year leases that began on the in-service dates of the generating units). As part of our carbon emission reduction goal, we have started implementing co-firing with natural gas at the ERGS coal-fired units. For information on our carbon emission reduction goal, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Corporate Developments.

Because of the significant investment necessary to construct these generating units, we constructed the plants under Wisconsin's Leased Generation Law, which allows a non-utility affiliate to construct an electric generating facility and lease it to the public utility. The law allows a public utility that has entered into a lease approved by the PSCW to recover fully in its retail electric rates that portion of any payments under the lease that the PSCW has allocated to the public utility's Wisconsin retail electric service, and all other costs that are prudently incurred in the public utility's operation and maintenance of the electric generating facility allocated to the utility's Wisconsin retail electric service. In addition, the PSCW may not modify or terminate a lease it has approved under the Leased Generation Law except as specifically provided in the lease or the PSCW's order approving the lease. This law effectively created regulatory certainty in light of the significant investment being made to construct the units. All four units were constructed under leases approved by the PSCW.

We are recovering our costs of these units, including subsequent capital additions, through lease payments that are billed from We Power to WE and then recovered in WE's rates as authorized by the PSCW and the FERC. Under the lease terms, our return is calculated using a 12.7% ROE and the equity ratio is assumed to be 55% for the ERGS units and 53% for the PWGS units.

Bluewater Natural Gas Holding, LLC

Bluewater, located in Michigan, primarily provides natural gas storage and hub services to our Wisconsin natural gas utilities. WE, WPS, and WG have entered into long-term service agreements for approximately one-third of their combined natural gas storage needs with a wholly owned subsidiary of Bluewater.

WEC Infrastructure LLC

At December 31, 2025, our non-utility energy infrastructure segment included WECI's ownership interests in the renewable generating facilities reflected in the table below.

Name	Ownership Interest	Commercial Operation
Bishop Hill III	90.0%	August 2018
Upstream	90.0%	January 2019
Coyote Ridge	82.6%	December 2019
Blooming Grove	90.0%	December 2020
Tatanka Ridge	85.7%	January 2021
Jayhawk	90.0%	December 2021
Thunderhead	90.0%	November 2022
Samson I [(1)]	90.0%	May 2022
Sapphire Sky	90.0%	February 2023
Maple Flats	90.0%	November 2024
Delilah I	90.0%	December 2024
Hardin III	90.0%	February 2025

[(1)] Although Samson I was commercially operational in May 2022, WECI didn't complete the purchase of its initial 80.0% ownership interest in this solar facility until February 2023. WECI completed the acquisition of an additional 10.0% of Samson I in January 2024, bringing its ownership interest in Samson I to 90.0%. See Note 2, Acquisitions, for more information.

Bishop Hill III, Coyote Ridge, Blooming Grove, Tatanka Ridge, Jayhawk, Thunderhead, Samson I, Sapphire Sky, Maple Flats, Delilah I, and Hardin III have offtake agreements with creditworthy counterparties for the sale of all of the energy they produce over periods ranging from 10 to 22 years following commercial operation. In addition, Upstream's revenue is substantially fixed over the 10-year period following commercial operation through an agreement with a creditworthy counterparty. Under the Tax Legislation, all of these investments qualify for PTCs. WECI is entitled to the tax benefits of Bishop Hill III, Upstream, Blooming Grove, Thunderhead, Samson I, Sapphire Sky, Maple Flats, Delilah I, and Hardin III in proportion to its ownership interest. WECI is entitled to 99% of the tax benefits of Coyote Ridge and Tatanka Ridge for the first 11 years following commercial operation, and is entitled to 99% of the tax benefits of Jayhawk for the first 10 years following commercial operation, after which WECI will be entitled to any tax benefits from these three facilities in proportion to its ownership interests. WECI recognizes PTCs as power is generated over a period of 10 years following commercial operation. Under the IRA transferability option, WEC Energy Group has sold substantially all of WECI's 2023 and 2024 generated PTCs to third parties. In addition, WEC Energy Group has either sold or entered into agreements to sell substantially all PTCs generated by WECI in 2025. A significant portion of WECI PTCs expected to be generated in 2026 are also under contract for sale to third parties. See Note 1(q), Income Taxes, for more information about the impact of these sales. See Note 16, Income Taxes, for more information on proceeds received related to the sale of PTCs.

See Note 2, Acquisitions, for more information on the more recent renewable generating facility acquisitions.

Seasonality

The electricity produced and revenues generated by the wind generating facilities depend heavily on wind conditions, which are variable. Operating results for wind generating facilities vary significantly from period to period depending on the wind conditions during the periods in question. Historically, wind production has been greater in the first and fourth quarters.

The electricity produced and revenues generated by the solar generating facilities is also variable and depends heavily on seasonality and weather conditions. Spring and summer are usually the peak solar production seasons due to increased direct sunlight and longer days. With regards to weather, solar panels will still work on cloudy and rainy days, but solar system output will be lower than on clear, sunny days. Also, major storms can damage solar panels and other equipment and lead to lower power generation until equipment can be repaired or replaced and brought back online. See Note 7, Property, Plant, and Equipment, for more information on the wind storms that damaged equipment at Samson I and Delilah I.

Corporate and Other Segment

The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, and the PELLC holding company, as well as the operations of Wispark and WBS. In addition, we have certain subsidiaries that hold investments in several clean energy investment funds and have engaged in certain financing activities. Wispark develops and invests in real estate, primarily in southeastern Wisconsin. WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated entities. WBS also provides certain administrative and support services to our nonregulated entities. This segment also includes Wisvest, WECC, and PDL which no longer have significant operations.

E. REGULATION

We are a holding company and are subject to the requirements of the PUHCA 2005. We also have various subsidiaries that meet the definition of a holding company under the PUHCA 2005 and are also subject to its requirements.

Pursuant to the non-utility asset cap provisions of Wisconsin's public utility holding company law, the sum of certain assets of all non-utility affiliates in a holding company system generally may not exceed 25% of the assets of all public utility affiliates. However, among other items, the law exempts energy-related assets, including the generating plants constructed by We Power and the other assets in our non-utility energy infrastructure segment, from being counted against the asset cap provided that they are employed in qualifying businesses. We report to the PSCW annually on our compliance with this law and provide supporting documentation to show that our non-utility assets are below the non-utility asset cap.

Regulated Utility Operations

In addition to the specific regulations noted above and below, our utilities are subject to various other regulations, which primarily consist of regulations, where applicable, of the EPA; the WDNR; the Illinois Department of Natural Resources; the Illinois Environmental Protection Agency; the Michigan Department of Environment, Great Lakes, and Energy; the Michigan Department of Natural Resources; the United States Army Corps of Engineers; the Minnesota Department of Natural Resources; and the Minnesota Pollution Control Agency.

Rates

Our utilities' rates are subject to the regulations and oversight of various state regulatory commissions and the FERC, as applicable. Decisions by these regulators can significantly impact our liquidity, financial condition, and results of operations. The following table compares our utility operating revenues by regulatory jurisdiction for each of the three years ended December 31:

	2025		2024		2023	
(in millions)	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
Electric						
Wisconsin	**$ 4,992.8**	**90.0 %**	$ 4,496.0	91.3 %	$ 4,548.8	90.8 %
Michigan	**171.8**	**3.1 %**	141.1	2.9 %	141.4	2.8 %
FERC – Wholesale	**382.8**	**6.9 %**	284.5	5.8 %	320.6	6.4 %
Total electric	**5,547.4**	**100.0 %**	4,921.6	100.0 %	5,010.8	100.0 %
Natural Gas						
Wisconsin	**1,743.8**	**44.0 %**	1,405.4	40.6 %	1,610.5	43.6 %
Illinois	**1,683.6**	**42.5 %**	1,602.4	46.3 %	1,557.8	42.2 %
Minnesota	**327.9**	**8.3 %**	290.5	8.4 %	348.4	9.4 %
Michigan	**203.9**	**5.2 %**	162.8	4.7 %	175.3	4.8 %
Total natural gas	**3,959.2**	**100.0 %**	3,461.1	100.0 %	3,692.0	100.0 %
Total utility operating revenues	**$ 9,506.6**		$ 8,382.7		$ 8,702.8	

Retail Rates

The state regulatory commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions including, but not limited to, approval of retail utility rates and standards of service, mergers, affiliate transactions, location and construction of electric generating units and natural gas facilities, and certain other additions and extensions to utility facilities. The PSCW, ICC, and MPUC also regulate security issuances at utilities in their respective jurisdictions. In addition, the FERC regulates security issuances for UMERC.

Historically, retail rates approved by the state commissions have been designed to provide utilities the opportunity to generate revenues to recover all prudently-incurred costs, along with a return on investment sufficient to pay interest on debt and provide a reasonable ROE. Rates charged to customers vary according to customer class and rate jurisdiction. WE, WPS, and WG are each subject to an earnings sharing mechanism in which a portion of the utility's earnings are required to be refunded to customers if the utility earns above its authorized ROE. See Note 26, Regulatory Environment, for more information on these earnings sharing mechanisms.

The table below reflects the various state commissions that regulated each of our utilities' retail rates during 2025, along with the approved ROE and capital structure for each utility during 2025.

Regulated Retail Rates	Regulatory Commission	Authorized ROE	Average Common Equity Component
WE – Electric, natural gas, and steam [(1)]	PSCW	9.80%	53.0%
WPS – Electric and natural gas	PSCW	9.80%	53.0%
WG – Natural gas	PSCW	9.80%	53.0%
UMERC – Electric	MPSC	9.86%	50.0%
PGL – Natural gas	ICC	9.38%	50.79%
NSG – Natural gas	ICC	9.38%	52.58%
MERC – Natural gas	MPUC	9.65%	53.0%
MGU – Natural gas	MPSC	9.86%	50.0%

[(1)] As currently proposed, the ROE for VLCs will range from 10.48% to 10.98%, as agreed upon with the customer, and the average common equity ratio will be 57.0%. See Note 26, Regulatory Environment, for more information.

In addition to amounts collected from customers through approved base rates, our utilities have certain recovery mechanisms in place that allow them to recover or refund prudently incurred costs that differ from those approved in base rates.

Embedded within our electric utilities' rates is an amount to recover fuel and purchased power costs. The Wisconsin retail fuel rules require a utility to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel and purchased power costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW typically sets at plus or minus 2% of the utility's approved fuel and purchased power cost plan. The deferred fuel and purchased power costs are subject to an excess revenues test. If the utility's ROE in a given year exceeds the ROE authorized by the PSCW, the recovery of under-collected fuel and purchased power costs would be reduced by the amount by which the utility's return exceeds the authorized amount. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers.

Our natural gas utilities operate under GCRMs as approved by their respective state regulator. Generally, the GCRMs allow for a dollar-for-dollar recovery of prudently incurred natural gas costs.

See Note 1(d), Operating Revenues, for additional information on the significant mechanisms our utilities had in place during 2025 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts.

Our utilities file periodic requests with their respective state commission for changes in retail rates. All of our utilities' rate requests are based on forward looking test years, which reflect additions to infrastructure and changes in costs incurred or expected to be incurred. For information on our regulatory proceedings, see Note 26, Regulatory Environment. Orders from our respective state regulators can be viewed at the following websites:

Regulatory Commission	Website
PSCW	https://psc.wi.gov/
ICC	https://www.icc.illinois.gov/
MPSC	http://www.michigan.gov/mpsc/
MPUC	http://mn.gov/puc/

The material and information contained on these websites are not intended to be a part of, nor are they incorporated by reference into, this Annual Report on Form 10-K.

Wholesale Rates

The FERC regulates our wholesale sales of electric energy, capacity, and ancillary services. Our electric utilities have received market-based rate authority from the FERC. Market-based rate authority allows wholesale electric sales to be made in the MISO market and directly to third parties based on the negotiated market value of the transaction. WE and WPS also make wholesale sales pursuant to cost-based formula rates. Cost-based formula rates provide for recovery of the utility's costs and an approved rate of return. The predetermined formula is initially based on the utility's expenses from the previous year, but is eventually trued up to reflect actual, current-year costs.

Electric Transmission, Capacity, and Energy Markets

In connection with its status as a FERC-approved RTO, MISO operates an energy and ancillary services market and manages the flow of high-voltage electricity across the transmission system in its region. MISO is responsible for monitoring and ensuring equal access to the electric transmission system in its footprint.

In MISO, transmission costs are allocated in accordance with the MISO tariff, which is reviewed and approved by the FERC. Base transmission costs are paid by load-serving entities located in the service territories of each MISO transmission owner. Costs for new regional transmission projects are allocated to load-serving entities throughout the MISO footprint, while the costs for new generation interconnections are allocated to the interconnection customer.

Within MISO, transmission congestion is monetized and included within an LMP that is established through the energy market. The LMP system includes the ability to hedge transmission congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO, and FTRs are purchased through auctions. A new allocation and auction was completed for the period of June 1, 2025, through May 31, 2026. The resulting ARR allocation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

MISO has seasonal zonal resource adequacy requirements to ensure there is sufficient generation capacity to serve load within each zone and the MISO footprint. To meet this requirement, load-serving entities can own generation and demand response resources, acquire generation capacity through MISO's annual capacity auction, or acquire generation capacity through bilateral contracts. The zone in which our electric utilities’ load resides, along with the MISO North region as a whole, has sufficient generation capacity resources to meet their respective planning reserve margins for the period between June 1, 2025 and May 31, 2026.

We manage our electric generation portfolios to minimize their exposure within MISO’s annual capacity auction. This includes managing the retirement of existing generation resources and the addition of new generation resources to maintain a diversified portfolio to help avoid a significant short position.

Other Electric Regulations

Our electric utilities are subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. Among other things, the Federal Power Act makes electric utility industry consolidation more feasible and authorizes the FERC to review proposed mergers and the acquisition of generation facilities. The FERC also oversees the Electric Reliability Organization, which establishes mandatory electric reliability standards and has the authority to levy monetary sanctions for failure to comply with these standards.

WE and WPS are subject to Act 141 in Wisconsin, and UMERC is subject to Public Acts 295 and 342 in Michigan, which contain certain minimum requirements for renewable energy generation.

Other Natural Gas Regulations

Almost all of the natural gas we distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services, including PGL's natural gas hub, are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the PHMSA and the state commissions are responsible for monitoring and enforcing requirements governing our natural gas utilities' safety compliance programs for our pipelines under the United States Department of Transportation regulations. These regulations include 49 CFR Part 191 (Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports), 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

We also continue to monitor the progress of the PHMSA’s proposed rulemaking titled "Gas Pipeline Leak Detection and Repair," which could have a significant impact on our natural gas utilities.

We are required to provide natural gas service and grant credit (with applicable deposit requirements) to customers within our service territories. We are generally not allowed to discontinue natural gas service during winter moratorium months to residential heating customers who do not pay their bills. Federal and certain state governments have programs that provide for a limited amount of funding for assistance to low-income customers of our utilities.

Non-Utility Energy Infrastructure Operations

The generation facilities constructed by wholly owned subsidiaries of We Power are being leased on a long-term basis to WE. Environmental permits necessary for operating the facilities are the responsibility of the operating entity, WE. We Power received determinations from the FERC that upon the transfer of the facilities by lease to WE, We Power's subsidiaries would not be deemed public utilities under the Federal Power Act and thus would not be subject to the FERC's jurisdiction.

Bluewater is regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the PHMSA is responsible for monitoring and enforcing requirements governing Bluewater's safety compliance programs for its pipelines under the United States Department of Transportation regulations. These regulations include 49 CFR Parts 191, 192, and 195. Given that Bluewater is required to route some of its natural gas through Canada, applicable reporting and licensing with the DOE and the Canadian National Energy Board are also required, along with routine reporting related to imports and exports.

All of our operational renewable generating facilities in our non-utility energy infrastructure segment are also subject to the FERC’s regulation of wholesale energy under the Federal Power Act.

Compliance Costs

The regulations and oversight described above significantly influence our operating environment, and may cause us to incur compliance and other related costs and may affect our ability to recover these costs from our utility customers. Any anticipated capital expenditures for compliance with government regulations for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Requirements.

F. ENVIRONMENTAL COMPLIANCE

Our operations, especially as they relate to our coal-fired generating facilities, are subject to extensive environmental regulation by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation, and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental regulations or revisions to existing laws, including for example, additional regulation related to GHG emissions, coal combustion products, air emissions, water use, or wastewater discharges and other climate change issues, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and certain remediation issues for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Requirements. For a discussion of certain environmental matters affecting us, including rules and regulations relating to air quality, water quality, land quality, and climate change, see Note 24, Commitments and Contingencies.

G. HUMAN CAPITAL

We believe our employees are among our most important resources, so investing in human capital is critical to our success. We strive to attract, retain, and develop talented personnel and keep our employees safe, healthy, and engaged.

Our Board of Directors retains collective responsibility for comprehensive risk oversight, including critical areas that could impact our sustainability, such as human capital. Management regularly reports to the Board of Directors on human capital management topics, including corporate culture, succession planning, training and employee development, and safety and health. The Board of Directors delegates specified duties to its committees. In addition to its responsibilities relative to executive compensation, the Compensation Committee has oversight responsibility for reviewing organizational matters that could significantly impact us. The Compensation Committee reviews recruiting and development programs and priorities, receives updates on key talent, and assesses workforce composition across the organization.

Workforce

As of December 31, 2025, we had the following number of employees, including those represented under union agreements:

	Total Employees	Union Employees
WE	2,565	1,963
WPS	1,220	876
WG	398	279
PGL	1,199	819
NSG	156	119
MERC	200	37
MGU	144	97
WBS	1,269	—
Total employees	7,151	4,190

We have a local union presence that spans Wisconsin, Illinois, Minnesota, and Michigan. We believe we have very good overall relations with our workforce.

In order to attract and retain talent, we provide competitive wages and benefits to our employees based on their performance, role, location, and market data. Our compensation package also includes a 401(k) savings plan with an employer match, an annual incentive plan based on meeting company goals, healthcare and insurance benefits, vacation and paid time off days, as well as other benefits.

Engagement

We are committed to ensuring a fair workplace and an engaged workforce. Our commitment is a core strategic competency and an integral part of our culture, with longstanding programs for individual development, reinforcement of our core values, and a recruitment strategy that is focused on building a deep talent pipeline to support our business needs. During 2025, we demonstrated this commitment through training and development of employees at all levels of the organization, our comprehensive merit review and succession planning processes, and a range of community partnerships. In addition, we have a number of initiatives that promote workforce contributions and participation and ensure our companies are attractive employers for persons of all backgrounds. These initiatives include nine business resource groups (voluntary, employee-led groups organized around a particular shared background or interest), mentoring programs, and education and training for all employees in order to develop and support inclusive teams. We are committed to a workplace free from bias and harassment. We also support external leadership and educational programs that support, train, and promote individuals in the communities we serve.

Safety and Health

Our Executive Safety Committee directs our safety and health strategy, works to ensure consistency across groups, and reinforces our ongoing safety commitment that we refer to as “Target Zero.” Under our Target Zero commitment, we have an ultimate goal of zero incidents, accidents, and injuries. Our corporate safety program provides a forum for addressing employee concerns, training employees and contractors on current safety standards, and recognizing those who demonstrate a safety focus. We monitor and set goals for days away, restricted or transferred metrics, and measurable leading indicators, which together raise awareness about employee safety and guide injury-prevention activities.

We also provide employees various benefits and resources designed to promote healthy living, both at work and at home. We encourage employees to receive preventive examinations and to proactively care for their health through free health screenings, wellness challenges, and other resources.

Development and Training

Employee training and development of both technical and leadership skills are integral aspects of our human capital strategy. We provide employees with a wide range of development opportunities, including online training, simulations, live classes, and mentoring to assist with their career advancement. These programs include safety and technical job skill training as well as soft-skill programs focused on relevant subjects, including communication and change management. Development of leadership skills remains a top priority and is specialized for all levels of employees. We have specific leadership programs for aspiring leaders and new supervisors, managers, and directors. This development of our employees is an integral part of our succession planning and provides continuity for our senior leadership.

ITEM 1A. RISK FACTORS

We are subject to a variety of risks, many of which are beyond our control, that may adversely affect our business, financial condition, and results of operations. You should carefully consider the following risk factors, as well as the other information included in this report and other documents filed by us with the SEC from time to time, when making an investment decision.

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental legislation, regulation, and oversight.

We are subject to significant state, local, and federal governmental legislation and regulations, including regulations by the various utility commissions in the states where we serve customers. Legislation and regulation significantly influence our operating environment, may affect our ability to recover costs from utility customers, affect our ability to implement our corporate strategy, and cause us to incur substantial compliance and other costs. Changes in legislation or regulations, their interpretation, or the imposition of new legislation or regulations could also significantly impact our business operations. Many aspects of our operations are impacted by government legislation and regulations, including, but not limited to: the rates we charge our retail electric, natural gas, and steam customers; the authorized rates of return of our utilities; construction and operation of electric generating facilities and electric and natural gas distribution systems, including the ability to recover such costs; decommissioning generating facilities, the ability to recover the related costs, and continuing to recover the return on the net book value of these facilities; wholesale power service practices; electric reliability requirements; participation in the interstate natural gas pipeline capacity market; standards of service; issuance of securities; short-term debt obligations; transactions with affiliates; and billing practices. Failure to comply with any applicable rules or regulations may lead to customer refunds, penalties, and other payments, which could materially and adversely affect our results of operations and financial condition.

The rates, including adjustments determined under riders, we are allowed to charge our customers for retail and wholesale services have the most significant impact on our financial condition, results of operations, and liquidity. Rate regulation provides us an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, our ability to obtain rate adjustments in the future is dependent upon regulatory action, the outcome of which can be influenced by the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; and changes in the political, regulatory, or legislative environments. There is no assurance that our regulators will consider all of our costs to have been prudently incurred. In addition, our rate proceedings may not always result in rates that fully recover our costs or provide for a reasonable ROE. We defer certain costs and revenues as regulatory assets and liabilities for future recovery from or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured and is subject to review and approval by our regulators. If recovery is not approved or is no longer deemed probable, these costs would be recognized in current period expense and could have a material adverse impact on our results of operations, cash flows, and financial condition.

Changes in the local and national political, regulatory, and economic environment, including significant attention on energy affordability concerns, have had, and may in the future have, an adverse effect on regulatory decisions, which could impair the ability of our utility subsidiaries to recover costs historically collected from customers. These decisions, which may come from any level of government, may cause us to cancel or delay current or planned projects, to reduce or delay other planned capital expenditures, or to pay for investments or otherwise incur costs that our utilities may not be able to recover through rates or otherwise. For example, the ICC's 2023 final rate order disallowed certain previously incurred capital costs, which resulted in PGL and NSG recording impairment losses in the fourth quarter of 2023, and caused PGL to pause spending on its PRP. PGL will include the costs of necessary infrastructure improvements related to the PRP in future rate cases, thereby subjecting the recovery of these costs to regulatory lag. In addition, in February 2025, the ICC issued an order setting expectations for PGL's prospective operations under its PRP. The ICC directed us to focus on replacing all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. The ICC indicated that failure to comply with this directive could subject us to civil penalties under Illinois statute.

Prior to its expiration in December 2023, the QIP rider provided PGL with recovery of, and a return on, qualifying natural gas infrastructure investments that were placed in service between regulatory rate reviews. This rider continues to be subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In February 2026, PGL agreed on the terms of a proposed settlement that would, among other things, resolve all proceedings of the open reconciliation years related to the QIP rider. As a result, we recorded a charge to income during the fourth quarter of 2025 through an impairment to net property, plant, and equipment and a reduction to revenues. The proposed settlement is subject to ICC approval. Otherwise, there can be no assurance that all costs incurred under the QIP rider during the open reconciliation years, including 2017 through 2023, will be deemed recoverable by the ICC, which could have a material adverse impact on PGL's, and correspondingly our, results of operations, financial condition, and liquidity.

We believe we have obtained the necessary permits, approvals, authorizations, certificates, and licenses for our existing operations, have complied in all material respects with all of their associated terms, and that our businesses are conducted in accordance with applicable laws. These permits, approvals, authorizations, certificates, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility and may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In addition, existing regulations may be revised or reinterpreted by federal, state, and local agencies, or these agencies may adopt new laws and regulations that apply to us. We cannot predict the impact on our business and operating results of any such actions by these agencies.

If we are unable to recover regulatory compliance costs or other associated costs in customer rates in a timely manner, or if we are unable to obtain, renew, or comply with governmental permits, approvals, authorizations, certificates, or licenses, our results of operations and financial condition could be materially and adversely affected.

We face significant costs to comply with existing and future environmental laws and regulations.

Our operations are subject to extensive and evolving federal, state, and local environmental laws, regulations, and permit requirements related to, among other things, air emissions (including, but not limited to CO_2, methane, mercury, SO_2, NOx, ozone and other pollutants), protection of natural resources, water quality, wastewater discharges, management of hazardous and toxic substances and solid wastes and soils, and climate change. Many of these rules are now the subject of a large deregulatory effort by the EPA and have resulted, and are expected to continue to result in, the adoption of new federal, state, and/or local level laws and regulations. Any EPA actions will require formal rulemaking proceedings and are likely to be subject to legal challenges. In addition, at the end of 2025, the President issued executive orders directing the DOE to issue orders keeping certain coal plants running for grid reliability despite utilities' plans to retire them. Future orders impacting our planned retirements of coal plants could impact our ability to execute on our capital plan and to meet our environmental goal. We continue to monitor the evolving regulatory landscape and standards for impacts on our business operations and financial condition.

Certain of our service territories in Wisconsin are located in areas that, in December 2024, were determined to be in "serious" nonattainment status under the EPA's ozone standard. In February 2025, the State of Wisconsin filed a petition for review of this classification in the U.S. Court of Appeals for the Seventh Circuit. Wisconsin subsequently moved for a stay of the reclassification, which was granted in September 2025, pending the Court's review. As a result, southeast Wisconsin has returned to "moderate" status while the underlying lawsuit proceeds. A nonattainment status of "serious" could affect future permitting activities for our facilities, including additional costs associated with more strenuous emission control requirements or the need to purchase emission reduction credits. In addition, economic growth in these areas may be constrained by the inability to obtain the required permits, limiting investment and expansion over the coming years, impacting our ability to execute on our capital plan.

We incur significant capital costs and expend operating resources to comply with environmental laws, regulations, and requirements, including costs associated with the installation of pollution control equipment; operating restrictions on our facilities; and environmental monitoring, emissions fees, and permits at our facilities. The operation of emission control equipment and compliance with rules regulating our intake and discharge of water could also increase our operating costs and reduce the generating capacity of our power plants. These regulations may create substantial additional costs in the form of taxes or emission allowances and could affect the availability and/or cost of fossil fuels and our ability to continue operating certain generating units. Failure to comply with these laws, regulations, and requirements, even if caused by factors beyond our control, may result in the assessment of civil or criminal penalties and fines. We continue to assess the cost of compliance and to explore different compliance alternatives with these and other environmental regulations. The cost of compliance with these regulations, and other factors, has resulted in certain of our coal-fired electric generating units being retired or converted to an alternative type of fuel, and may impact the future operations of our existing fossil-fueled generation.

Our electric and natural gas utilities are also subject to significant liabilities related to the investigation and remediation of environmental impacts at certain of our current and former facilities and at third-party owned sites. We accrue liabilities and defer costs (recorded as regulatory assets) incurred in connection with our former manufactured gas plant sites. These costs include all costs incurred to date that we expect to recover, management's best estimates of future costs for investigation and remediation and related legal expenses, and are net of amounts recovered (or that may be recovered) from insurance or other third parties. Due to the potential for the imposition of stricter standards and greater regulation in the future, the possibility that other potentially responsible parties may not be willing or financially able to contribute to cleanup costs, a change in conditions or the discovery of additional contamination, our remediation costs could increase, and the timing of our capital and/or operating expenditures in the future may accelerate or could vary from the amounts currently accrued.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, occurs frequently throughout the United States. This litigation has included claims for damages alleged to have been caused by GHG and other emissions and exposure to regulated substances and/or requests for injunctive relief in connection with such matters. In addition to claims relating to our current facilities, we may also be subject to potential liability in connection with the environmental condition of facilities that we previously owned and operated, regardless of whether the liabilities arose before, during, or after the time we owned or operated these facilities. If we fail to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, that failure or harm may result in the assessment of civil penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a material adverse effect on our results of operations and financial condition.

In the event we are not able to recover all of our environmental expenditures and related costs from our customers in the future, our results of operations and financial condition could be adversely affected. Further, increased costs recovered through rates could contribute to reduced demand for electricity and natural gas, which could adversely affect our results of operations, cash flows, and financial condition.

Our operations, capital expenditures, and financial results may be affected by the impact of greenhouse gas legislation, regulation, and our emission reduction goal.

There has been significant attention to issues concerning climate change as well as activism from certain stakeholders, including institutional investors and other sources of financing, to accelerate the transition to limit GHG emissions. Although the EPA is pursuing a large deregulatory effort of GHG laws and regulations, significant laws and regulations restricting emissions of GHGs continue to impact our current and planned operations. Costs associated with such legislation, regulation, and our emission reduction goal could be significant within our electric and natural gas operations. New or additional restrictive GHG legislation or regulations may cause our environmental compliance spending to differ materially from the amounts currently estimated. There is no guarantee that we will be allowed to fully recover compliance costs of these and other federal and state regulations, or that cost recovery will not be delayed or otherwise conditioned. GHG legislation, regulation, or the emission reduction goal, as well as changes in the fuel markets and advances in technology could make electric generating units uneconomic to maintain, may impact how we operate our existing fossil-fueled power plants and biomass facility, and could cause us to retire and replace units earlier than planned under our capital plan, which could lead to a possible loss on abandonment and reduced revenues.

In a movement toward electrification, certain states and municipalities near or in our service territories have passed legislation or are considering ordinances banning natural gas used in new construction in order to limit GHG emissions. For example, the ICC is exploring the role of natural gas in the future and issues related to decarbonization of the natural gas distribution system in Illinois. There have also been efforts to restrict residential natural gas-fired appliances. Future actions like these to regulate GHG emissions in our service territories could increase the price of natural gas resulting in reduced demand for, and revenues from, natural gas, cause us to accelerate the replacement and/or updating of our natural gas delivery systems, and adversely affect our ability to operate our natural gas facilities. The adoption of electrification initiatives and/or mandates could also result in an increase in electrical demand and increased investment costs for existing or new electrical systems. These types of initiatives and/or mandates could result in increased costs associated with permitting and siting of new technologies and delayed installation and start-up timelines. In addition, financial investments in older carbon-intensive technologies may not be fully realized.

We have set a goal for our generation fleet to be net carbon neutral by the end of 2050. We expect to be in a position to eliminate coal as an energy source by the end of 2032. In addition, we continue to monitor the financial and operational feasibility of taking more aggressive action to further reduce GHG emissions in order to limit future global temperature increases. The ability to achieve this goal depends on many external factors, including the ability to make operating refinements, the retirement of less efficient generating units, the development of relevant energy technologies, the use of RNG throughout our natural gas utility systems, the ability to procure renewable thermal credits, legislative and regulatory support for renewable generation, the ability to maintain reliability with demand growth, and the ability to execute our capital plan.

Changes in tax legislation, IRS audits, or our inability to use certain tax benefits and carryforwards, may adversely affect our financial condition, results of operations, and cash flows, as well as our credit ratings.

Tax legislation and regulations can adversely affect, among other things, our financial condition, results of operations, cash flows, liquidity, and credit ratings. In July 2025, the OBBBA was signed into law, enacting significant modifications to clean-energy tax credits previously provided under the IRA. The OBBBA provides companies the ability to earn solar and wind tax credits at current credit rates under new beginning of construction rules. Solar and wind tax incentives can be denied for energy projects that use equipment beyond statutory guidelines from prohibited foreign entities or for taxpayers that exceed certain thresholds of equity or debt held by prohibited foreign entities.

Future changes to corporate tax rates or policies, including under Treasury Regulations and guidance issued in connection with the IRA and OBBBA, could require us to take material charges against earnings. Such changes include, among other things, increasing the federal corporate income tax rate, disallowing or limiting the use of solar and wind tax incentives and other tax benefits and carryforwards, limiting interest deductions, and altering the expensing of capital expenditures. Our inability to manage these changes, an adverse determination by one of the applicable taxing jurisdictions, or additional interpretations, implementing regulations, amendments, or technical corrections by the Treasury Department, the IRS, or state income tax authorities, could significantly impact our financial results and cash flows.

We have significantly reduced our consolidated federal and state income tax liabilities in the past through tax credits, net operating losses, and charitable contribution deductions. A reduction in or disallowance of these tax benefits could adversely affect our earnings and cash flows. We have not fully used these allowed tax benefits in our previous tax filings and have carried them forward to use against future taxable income. Our inability to generate sufficient taxable income in the future to fully use these tax carryforwards before they expire, or to transfer future tax credits as discussed below, could significantly affect our tax obligations and financial results.

In addition, we have invested, and plan to continue to invest, in renewable energy generating facilities. These facilities generate PTCs or ITCs that we can use to reduce our federal tax obligations. Under the IRA, a transferability option also allows us to sell these tax credits to third parties. The amount of tax credits we earn depends on available government incentives and policies, the amount of electricity produced, the applicable tax credit rate, or the amount of the investment in qualifying property. Reductions or eliminations of tax credits or other governmental incentives that promote renewable energy generating facilities, or the imposition of additional taxes, tariffs, or other assessments related to renewable energy projects or the equipment necessary to generate or deliver it, may limit our ability to make further investments in renewable energy generating facilities or reduce the returns on our existing investments. In addition, a variety of operating and economic factors, including transmission constraints, adverse weather conditions, and breakdown or failure of equipment, could significantly reduce the PTCs generated by the renewable projects we have invested in, any of which could result in a material adverse impact on our financial condition and results of operations.

We are also uncertain as to how credit rating agencies, capital markets, the FERC, or state public utility commissions will treat any future changes to federal or state tax legislation. These impacts could subject us to credit rating downgrades. In addition, certain financial metrics used by credit rating agencies, such as our funds from operations-to-debt percentage, could be negatively impacted by changes in federal or state income tax legislation.

Our electric utilities could be subject to higher costs and penalties as a result of mandatory reliability standards.

Our electric utilities are subject to mandatory reliability and critical infrastructure protection standards established by the North American Electric Reliability Corporation and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. Noncompliance with the mandatory reliability standards could result in sanctions, including substantial monetary penalties, or damage to our reputation.

Provisions of the Wisconsin Utility Holding Company Act limit our ability to invest in non-utility businesses and could deter takeover attempts by a potential purchaser of our common stock that would be willing to pay a premium for our common stock.

Under the Holding Company Act, we remain subject to certain restrictions that have the potential of limiting our diversification into non-utility businesses. Under the Holding Company Act, the sum of certain assets of all non-utility affiliates in a holding company system generally may not exceed 25% of the assets of all public utility affiliates in the system, subject to certain exemptions for energy-related assets.

In addition, the Holding Company Act precludes the acquisition of 10% or more of the voting shares of a holding company of a Wisconsin public utility unless the PSCW has first determined that the acquisition is in the best interests of utility customers, investors, and the public. This provision and other requirements of the Holding Company Act may delay or reduce the likelihood of a sale or change of control of WEC Energy Group. As a result, shareholders may be deprived of opportunities to sell some or all of their shares of our common stock at prices that represent a premium over market prices.

Risks Related to the Operation of Our Business

Public health crises, including epidemics and pandemics, could adversely affect our business functions, financial condition, liquidity, and results of operations.

Public health crises, including epidemics and pandemics, and any related government responses may adversely impact the economy and financial markets and could have a variety of adverse impacts on us, including a decrease in revenues; increased bad debt expense; increases in past due accounts receivable balances; and access to the capital markets at unreasonable terms or rates. These crises and any related government responses could also impair our ability to develop, construct, and operate facilities. Risks include extended disruptions to supply chains and inflation, resulting in increased costs for labor, materials, and services, which could adversely impact our ability to implement our corporate strategy. We may also be adversely impacted by labor disruptions and productivity as a result of infections, employee attrition, or the inability to replace or maintain appropriate staffing. The extent to which future public health crises may affect us depends on factors beyond our knowledge or control. As a result, we are unable to determine the potential impact any such public health crises may have on our business plans and operations, liquidity, financial condition, and results of operations.

Our operations are subject to risks arising from the reliability and safety of our electric generation, transmission, and distribution facilities, natural gas infrastructure facilities, natural gas storage fields, renewable energy facilities, and other facilities, as well as the reliability of third-party transmission providers.

Our financial performance depends on the successful operation of our electric generation and transmission, natural gas and electric distribution facilities, natural gas storage fields, and renewable energy facilities. Inherent in electric generation and distribution and natural gas transportation, distribution, and storage activities are a variety of hazards and operational risks, including accidents, operator error, and the breakdown or failure of equipment or processes including leaks, accidental explosions, mechanical problems, fires, discharges or releases of toxic or hazardous substances or gases, and other environmental risks. Potential breakdown or failure may occur due to severe weather (i.e., storms, tornadoes, floods, droughts, etc.); catastrophic events (i.e., fires, earthquakes, and explosions); public health crises; significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; delays in the replacement of aging infrastructure; shortages of or delays in obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist or other physical attacks; or cybersecurity intrusions.

The location of natural gas pipelines and storage facilities near populated areas could increase the level of damages resulting from these risks. Unplanned outages at our power plants may cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations. Because our electric generation and renewable energy facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by events impacting their systems.

These hazards and operational risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, and impairment of operations. They may also subject us to litigation and/or administrative proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, or be resolved on unfavorable terms. Any of these events could lead to substantial financial losses, including increased maintenance costs, unanticipated capital expenditures, and a reduction of revenues, which could materially and adversely affect our results of operations, financial condition, and cash flows.

The operations of our natural gas utilities depend upon the availability of adequate interstate pipeline transportation capacity and natural gas.

Our natural gas utilities purchase almost all of their natural gas supply from interstate sources that must be transported to the applicable service territories. Interstate pipeline companies transport the natural gas to our natural gas utilities' systems under firm service agreements that are designed to meet the requirements of their core markets. Certain of our natural gas facilities have experienced significant disruptions to operations as a result of problems with interstate pipelines. A significant disruption to interstate pipelines capacity or reduction in natural gas supply due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze-off of natural gas wells, terrorist or physical attacks, cyberattacks, other acts of war, or legislative or regulatory actions or requirements, including remediation related to integrity inspections or regulations and laws enacted to address climate change or other environmental matters, could reduce the normal interstate supply of natural gas and thereby significantly disrupt our operations and/or reduce earnings.

Our operations are subject to various conditions that can result in fluctuations in energy sales to customers, including fluctuations in customer growth and general economic conditions in our service areas, varying weather conditions, and energy conservation efforts.

Our results of operations and cash flows are affected by the demand for electricity and natural gas, which can vary greatly based upon:

- *Fluctuations in customer growth and general economic conditions in our service areas.* Customer growth and energy use can be negatively impacted by population declines as well as economic factors in our service territories, including workforce reductions, stagnant wage growth, changing levels of support from state and local government for economic development, business closings, and reductions in the level of business investment. Our electric and natural gas utilities are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn, disruption of financial markets, or reduced incentives by state government for economic development could adversely affect the financial condition of our customers and demand for their products or services. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.
- *Weather conditions*. Demand for electricity is greater in the summer and winter months when cooling and heating is necessary. Demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate on a seasonal basis and could be negatively impacted by milder temperatures during the summer cooling season and winter heating season.
- *Our customers' continued focus on energy conservation*. Our customers' use of electricity and natural gas has decreased as a result of continued individual conservation efforts, including the use of more energy efficient technologies, and could be further reduced by new building codes, DERs, energy storage technology, and private solar. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income and increases in energy prices. Conservation of energy can be influenced by certain federal and state programs that are intended to influence how consumers use energy. For example, several states, including Wisconsin and Michigan, have adopted energy efficiency targets to reduce energy consumption.

As part of our planning process, we estimate the impacts of changes in customer growth and general economic conditions, weather, and customer energy conservation efforts, but risks still remain. Any of these matters, as well as any regulatory delay in adjusting rates as a result of fluctuations in energy demand or the adoption of new technologies, could adversely impact our results of operations and financial condition. In addition, elimination or reduced financial support of programs that provide energy assistance to our customers, including the Low Income Home Energy Assistance Program, could impact the demand for energy and/or adversely impact our liquidity.

Our operations are subject to the effects of global climate change.

A changing climate creates uncertainty and could result in broad changes, both physical and financial in nature, to our service territories. If climate changes occur that result in extreme temperatures in our service territories, our financial results could be adversely impacted by lower electric and natural gas usage and higher natural gas costs. Our operations could be adversely affected and our facilities placed at greater risk of damage should changes in global climate produce, among other possible conditions, unusual variations in temperature and weather patterns, which could result in more intense, frequent and extreme weather events, such as storms, including derecho events, with high winds, lightning, and hail, floods, drought, wild fires, tornadoes, snow and ice storms, or abnormal levels of precipitation. An extreme weather event could result in damage to distribution and transmission infrastructure, wind and solar generation facilities, or other operating equipment. This could result in us incurring significant restoration costs at our utilities and/or at WECI, and foregoing sales of energy and lost revenues. Extreme weather in summer could cause electric load to be interrupted or certain customers to be curtailed who participate in load management programs. Additionally, an extreme weather event could also cause the cost of natural gas purchased for our natural gas utility customers and for the use of fuel at our generation facilities to be temporarily driven significantly higher than our normal winter weather expectations. Although our utilities have regulatory mechanisms in place for recovering all prudently incurred natural gas costs, our regulators could disallow recovery or order the refund of any costs determined to be imprudent.

Extreme weather may also result in unexpected increases in customer load, requiring us to procure additional power at wholesale prices for our retail operations, unpredictable curtailment of customer load by MISO to maintain grid reliability, or other grid reliability issues. Any of these events could lead to substantial financial losses including increased maintenance costs, unanticipated capital expenditures, or a reduction of revenues related to our non-utility renewable energy facilities. The cost of storm restoration efforts may also not be fully recoverable through the regulatory process.

Changes in our corporate strategy to combat climate change, including mitigation and adaptation efforts and technology advancement, may materially adversely impact our results of operations and cash flows.

Our operations and future results may be impacted by changing expectations and demands of our customers, regulators, investors, and other stakeholders.

Our ability to execute our corporate strategy and achieve anticipated financial outcomes are influenced by the expectations of our customers, regulators, investors, and other stakeholders. Those expectations are based in part on the core fundamentals of affordability and reliability but are also increasingly focused on our ability to meet rapidly changing demands for new and varied products, services, and offerings. Efforts to roll back certain environmental rules and social policies and programs may conflict with the expectations of our customers, regulators, or investors, creating additional uncertainty as we look to balance our stakeholders' competing priorities, and could lead to litigation and government investigations. Failure to meet these expectations or to adequately address the risks and external pressures may impact our reputation and affect our ability to achieve favorable outcomes in future rate cases or our results of operations. Furthermore, the increasing use of social media may accelerate and increase the potential scope of negative publicity we might receive and could increase the negative impact on our reputation, business, results of operations, and financial condition.

Our operations and corporate strategy may be adversely affected by supply chain disruptions, inflation, and tariffs.

Our business is dependent on the global supply chain to ensure that equipment, materials, and other resources are available to both expand and maintain services in a safe and reliable manner. Increased tensions between the United States and other countries, as well as new, protracted, or escalating regional or international conflicts could result in domestic and global supply chain disruptions that delay the delivery, or result in shortages of, materials, equipment, and other resources that are critical to our business operations. Failure to eliminate or manage the constraints in the supply chain may eventually impact the availability of items that are necessary to support normal operations as well as materials that are required to implement our corporate strategy for continued utility and infrastructure growth, including our renewable energy projects.

Prices of equipment, materials, and other resources have increased and may continue to increase in the future, as a result of supply chain disruptions, inflation, and tariffs. Further governmental actions related to trade policy could exacerbate global supply chain disruptions and/or inflation. Increased costs for labor, materials, and services, as a result of supply chain disruptions, inflation, or tariffs, and failure to secure these resources on economically acceptable terms, as well as any regulatory delay in adjusting rates to account for increased costs, may adversely impact our business operations, financial condition, and/or capital plan.

We are actively involved with multiple significant capital projects, which are subject to a number of risks and uncertainties that could adversely affect project costs and completion of construction projects.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas and LNG storage, and other projects, including projects for environmental compliance. We also expect to continue constructing and investing in renewable energy and natural gas generating facilities as part of our capital plan and our goal to be net carbon neutral by the end of 2050. In addition, we continue to invest in technology and the development of software applications to support our businesses.

Achieving the intended benefits of any large construction project is subject to many uncertainties, some of which we will have limited or no control over, that could adversely affect project costs and completion time. Supply chain disruptions, including solar panel shortages and delays, increasing material costs, government regulations and tariffs, and other factors, could impact the timing of completion of our renewable projects. Additional risks include, but are not limited to, the ability to adhere to established budgets and time frames; the availability of labor or materials at estimated costs; the ability of contractors to perform under their contracts; strikes; adverse weather conditions; potential legal challenges; changes in applicable laws or regulations; rising interest rates; inflation; tariffs; the impact of public health crises; other governmental actions; continued public and policymaker support for such projects; and events in the global economy.

Certain of these projects require the approval of our regulators. If construction of commission-approved projects should materially and adversely deviate from the schedules, estimates, and/or projections on which the approval was based, our regulators may deem the additional capital costs as imprudent and disallow recovery of them through rates, and otherwise available PTCs and ITCs for renewable energy projects could be lost or lose value. Efforts to pause approvals related to wind development could threaten our ability to execute our capital plan. Other renewable energy sources, including solar developments, could also be at risk. In addition, regulators, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed, such as was the case in the ICC's November 2023 rate orders and annual QIP reconciliation reviews for PGL.

To the extent that delays occur, costs become unrecoverable, tax credits are lost or lose value, or we or third parties with whom we invest and/or partner otherwise become unable to effectively manage and complete capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

We face risks related to providing service to our large-scale customers, including potential customers under our proposed VLC and Bespoke Resources Tariffs, which could impact our business, results of operations, and financial condition.

We are engaged in discussions with a small number of customers to provide power to large-scale data centers being constructed to support AI and other technology capabilities. Because of the significant demand and energy needs associated with these facilities, extending service to these facilities requires investment in incremental electric infrastructure. Subject to pending regulatory approvals from the PSCW, WE has made and will continue to make significant infrastructure investments in new solar and battery projects, natural gas power plants, and other generation and distribution assets to power and serve these large-scale data centers and other projects. Our transmission affiliate, ATC, also has made and will continue to make significant investments in additional transmission infrastructure to serve the increased customer load.

In March 2025, WE filed an application with the PSCW requesting approval to implement a VLC Tariff and a Bespoke Resources Tariff. Under these proposed inter-connected tariffs, VLCs directly pay for the electricity they consume, along with the power plants and distribution facilities built to serve them and transmission costs allocated to their usage. The proposed tariffs are designed so that the costs associated with these VLCs are not subsidized by or shifted to residential or other business customers. WE is incurring significant engineering, design, and equipment costs in advance of receiving approval of the tariffs as well as necessary regulatory and other approvals for the needed generation, distribution, and transmission projects. If any of these projects are canceled for any reason, including due to lower than forecasted demand or for failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have already been recorded as an asset, an impairment loss may need to be recorded. We may not be allowed to recover these penalties, other costs incurred, or impairment losses in customer rates, which could have a material adverse effect on our results of operations. WE requires VLCs to enter into payment and cancellation agreements which obligate the VLC to reimburse WE for all costs associated with projects requested by the customer until service agreements are executed under the approved tariffs. Reimbursement is also required if, among other things, the VLC terminates the payment and cancellation agreement or reduces its anticipated load, or regulatory approval is not received for the construction of a project. Despite these risk mitigating efforts, we may still experience significant losses or delayed recovery of these costs. In addition, the ability to obtain regulatory approval of one or more projects and/or the VLC and Bespoke Resources Tariffs may affect our ability to recover costs with acceptable conditions for these large-scale customers.

The ability to complete large capital projects is dependent upon a number of factors, including the ability to obtain financing of such projects on satisfactory terms and conditions. Along with the significant capital spend, a portion of the expected earnings growth from these projects will result in an increase in AFUDC as part of CWIP, with recovery of these costs delayed until the capital project is placed in service. As a result of this delay in receiving cash proceeds, we may be required to issue additional debt and/or equity to support these projects, which could negatively impact our earnings, balance sheet, and/or credit metrics. Other dependent factors include the ability to secure regulatory permits, secure sufficient land for the siting of power generation facilities, obtain necessary interconnection or transmission service in MISO, garner public support for these projects, and the ability of suppliers and contractors to fulfill their obligations under contracts. Successful completion of these projects may be further influenced by changes in law or regulation, such as new legislation or regulation impacting large data center cost allocation or environmental compliance requirements, trade and tariff issues, including those associated with imported solar panels, as well as supply chain delays or disruptions, workforce challenges, and other events beyond our control. If these projects are significantly delayed or become subject to cost overruns or cancellation due to these or other factors, we could incur additional costs and termination payments or face increased risk of potential write-offs of our investments in these projects. The occurrence of any of these events may materially affect the schedule, cost, and performance of these projects.

This concentration of business with a small number of customers in an industry based on emerging technologies, including AI and machine learning, presents several risks. We cannot predict the rate at which or the extent to which these emerging technologies will be broadly adopted and successful as business models. Changes in industry practice or advances in these technologies could reduce the demand for electricity to power data centers. Significant capital spend to build out required infrastructure or a downturn in business could cause the loss of these customers or may weaken their financial condition, liquidity and/or creditworthiness, including their ability to satisfy their reimbursement obligations to us. Similarly, customers may reduce their investment in these new technologies or abandon them entirely.

Any of these situations may result in the early termination or non-renewal of these customers’ electric service agreements or renewal on terms less favorable to us. Electric service agreements with these customers include provisions for early termination payments, but they may not fully protect against all risks. While the assets constructed to serve these customers may otherwise be useful in our utility operations, there is a risk that we may not be able to fully recover our investment in or a return on those assets.

Our business, results of operations, and financial condition could be materially adversely affected as a result of any or all of these factors.

Our operations are subject to risks beyond our control, including but not limited to, cybersecurity intrusions, terrorist or other physical attacks, acts of war, or unauthorized access to personally identifiable information.

We have been subject to attempted cyber attacks from time to time, and will likely continue to be subject to such attempted attacks; however, these prior attacks have not had a material impact on our system or business operations. All of our assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to physical or cybersecurity intrusions caused by human error, vendor bugs, terrorist or other physical attacks (including potential attacks on our substations and other electric distribution equipment), acts of war, or other malicious acts. Cybersecurity threats could result in a full or partial disruption of our ability to generate, transmit, purchase, or distribute electricity or natural gas or cause environmental repercussions. If our assets or systems were to fail, be physically damaged, or be breached, and were not recovered in a timely manner, we may be unable to perform critical business functions, and data, including sensitive information, could be compromised. Cybersecurity attacks, including attacks targeting utility systems and other critical infrastructure, may increase during periods of heightened or escalating geopolitical tensions.

We operate in an industry that requires the use of sophisticated information technology systems and network infrastructure, which in turn control an interconnected network of generation, distribution, and transmission systems shared with third parties. A successful physical or cybersecurity intrusion may occur despite our security measures or those we require of our vendors, including compliance with reliability and critical infrastructure protection standards. Successful cybersecurity intrusions, including those targeting the electronic control systems used at our generating facilities and electric and natural gas transmission, distribution, and storage systems, could disrupt our operations and result in loss of service to customers. Attacks may come through ransomware, software updates or patches, or firmware that hackers can manipulate. These intrusions may cause unplanned outages at our power plants, which may reduce our revenues or cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses. The risk of such intrusions may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

Our continued efforts to integrate, consolidate, and streamline our operations have also resulted in increased reliance on current and recently completed projects for technology systems. The failure to enhance existing information technology systems and adopt or successfully implement new technology could adversely affect our operations. Cybersecurity threats, including those leveraging AI, continue to increase, and the security measures and preventative actions we take to reduce the risk of cybersecurity incidents and protect our systems against unauthorized access to secured data and systems may be insufficient to safeguard against all security breaches. The failure of any of these important technologies, or our inability to support, update, expand, and/or integrate these technologies across our subsidiaries, could materially and adversely impact our operations, diminish customer confidence and our reputation, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation.

Our business requires the collection and retention of personally identifiable information of our customers, shareholders, and employees, who expect that we will adequately protect such information. In some cases, we rely on third-party hosted services to support our business operations. Malicious actors may target these providers to disrupt the services they provide to us, or to use those third parties to attack us. Security breaches of our or our third-party service providers' systems may expose us to a risk of loss or misuse of confidential and proprietary information. A significant theft, loss, or fraudulent use of personally identifiable information may lead to potentially large costs to notify and protect the impacted persons, and/or could cause us to become subject to significant litigation, costs, liability, fines, or penalties, any of which could materially and adversely impact our results of operations as well as our reputation with customers, shareholders, and regulators, among others. In addition, we may be required to incur significant costs associated with governmental actions in response to such intrusions or to strengthen our information and electronic control systems. We may also need to obtain additional insurance coverage related to the threat of such intrusions.

Threats to our systems and operations continue to emerge as new ways to compromise components into our systems or networks are developed. Any operational disruption or environmental repercussions caused by on-going or future threats to our assets and technology systems could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations, financial condition, and cash flows. The costs of repairing damage to our facilities, operational disruptions, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may also not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

Adoption of AI technologies could adversely affect our business, reputation, or financial results.

We are using AI primarily through services provided by our third party vendors. In addition, we are exploring the use of AI, including generative AI, and its ability to enhance the services we offer. There are significant risks involved in developing and deploying AI, and there can be no assurance that the use of AI will enhance our services or be beneficial to our business, including with respect to the efficiency and resiliency of our systems. Our AI-related efforts may give rise to risks related to accuracy, bias, discrimination, intellectual property infringement or misappropriation, data privacy, and cybersecurity, among others. In addition, the adoption of AI may subject us to new or enhanced governmental or regulatory scrutiny, laws, rules, directives, or regulations governing the use of AI, as well as litigation, ethical concerns, negative customer perceptions as to automation and AI, legal liability or other complications that could adversely affect our business, reputation, or financial results. We may not be able to recover our investments in AI technology through our regulatory proceedings. Similarly, as AI continues to evolve, we may not be able to adopt and implement AI as quickly as our customers or communities desire or regulators may require. AI is a relatively new and rapidly evolving technology, and we are unable to predict all of the risks that may result from our and our vendors' adoption of AI initiatives.

Advances in technology, and legislation or regulations supporting such technology, could make our electric generating facilities less competitive and may impact the demand for natural gas.

Advances in new technologies that produce or store power or reduce power consumption are ongoing and include renewable energy technologies, customer-oriented generation, energy storage devices, and energy efficiency technologies. We generate power at central station power plants and utility-scale renewable generation facilities to achieve economies of scale and produce power at a competitive cost. Distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, solar cells, and related energy storage devices, have technologically improved and have become more cost competitive than they were in the past.

Legislation, including the IRA and the Infrastructure Investment and Jobs Act, has promoted the construction and cost-effectiveness of renewable energy generation, including distributed generation technologies for self-supply of electricity by our customers and third parties. Increased use of technologies such as private solar and battery storage in our service territories could reduce our recovery of fixed costs, could result in customers leaving the electric distribution system, and could cause an increase in customer net energy metering, which allows customers with private solar to receive bill credits for surplus power at the full retail amount. Over time, customer adoption of these technologies could result in our electric utilities not being able to fully recover the costs and investment in generation.

Federal and state regulations and other efforts designed to promote and expand the use of distributed generation technologies also incentivize modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity and increase the grid's capacity to interconnect to these distributed generation technologies. Other legislation or regulations could be adopted supporting the use of these technologies at below cost or that permit third-party sales from such facilities, and allow these facilities to interconnect to our distribution system. There is also a risk that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station and utility-scale renewable power production. In addition, regulatory support of co-locating generation near data centers could impact our generation planning and its related cost recovery and could cause our generation to be less cost effective.

We also cannot predict the effect that development of alternative energy sources or new technology may have on our natural gas operations, including whether subsidies of alternative energy sources by local, state, and federal governments might be expanded, or what impact this might have on the supply of or the demand for natural gas.

If these technologies become cost competitive and achieve economies of scale, our market share could be eroded, and the value of our generating facilities and natural gas distribution systems could be reduced. Advances in technology, or changes in legislation or regulations, could also change the channels through which our customers purchase or use power and natural gas, which could reduce our sales and revenues or increase our expenses.

We face risks related to our non-utility renewable energy facilities that could impact our return on investment or have a negative impact on our financial condition or results of operations.

The production of energy from wind and solar sites depends heavily on suitable weather conditions, which are variable. Wind conditions or solar irradiance that is unfavorable or below our estimates can cause electricity production, and therefore revenues and PTCs earned from non-utility renewable energy facilities, to be substantially below our expectations. We based our decisions about which sites to acquire and operate in part on the findings of studies of long-term meteorological data in the proposed area. Actual conditions at these sites, however, may not conform to the results of these studies.

Our renewable sites may experience performance issues and production shutdowns as a result of the quality of the wind turbine and solar panel components used in construction, as well as due to the availability of replacement parts. In addition, an increase in frequency and severity of weather conditions could cause disruptions to our sites to become more frequent and severe. Wind and solar equipment can be damaged by natural events such as lightning strikes that damage blades or in-ground systems used to collect electricity from turbines or panels. Sites also may experience production shutdowns or delayed restoration of production during extreme weather conditions resulting in, among other things, damage to solar panels, icing on wind turbine blades, or restricted access to sites. The costs of repairing damage to these facilities may exceed the insurance limits on our insurance policies or may be outside the coverage afforded by our insurance policies. In addition, significant repair costs and/or continuous damage events could cause our insurance premiums to increase or lead to insurance coverage not being available at all. Damage to renewable facilities could also reduce operating capacity and cause the declaration of force majeure events. Customers may raise objections to force majeure declarations for these or similar operating issues. The failure to satisfy minimum operational or availability requirements under the PPAs could result in payment of damages or termination of the PPAs.

Lower wholesale market prices for electricity may adversely affect the financial results for certain of our renewable projects, depending on the structure of the related PPA. In addition, lower prices for other energy sources may reduce the demand for wind and solar energy development, which could adversely affect our growth prospects and financial condition. Wind and solar energy demand is affected by the price and availability of other fuels, including nuclear, coal, natural gas and oil, as well as other sources of renewable energy. Reduced government incentives for wind and solar energy, increases in operating and maintenance costs, new regulations, or incentives that favor other forms of energy could reduce the demand for renewable energy and may adversely affect our results of operations.

We do not own all the property and other sites on which our projects are located. Projects may be located on property or other sites occupied under long-term easements, leases, and rights of way. The ownership interests on these properties may be subject to mortgages securing loans or other liens and other easements, lease rights, and rights of way of third parties that were created previously. As a result, some of our real property rights may be subordinate to the rights of third parties, and the rights of our operating subsidiaries to use the property could be lost or curtailed, which could have an adverse effect on our business and financial conditions.

We have entered into long-term PPAs for the majority of our non-utility renewable energy operations with a small number of customers where their payment is based on the energy produced, and in some cases the REC value created, by our facilities. Although initial agreements are often ten years or more, in the future we may not be able to replace expiring PPAs related to our non-utility renewable energy facilities with contracts on acceptable terms, including at prices that support profitable operation of the facility. Decreases in the retail prices of electricity supplied by traditional utilities or the pricing of other clean energy sources in the regions where our non-utility renewable energy facilities are located could harm our ability to offer competitive pricing and to sign PPAs with customers. If we are unable to replace an expiring PPA with an acceptable new revenue contract, we may be required to sell the power produced by the facility at wholesale prices and be exposed to market fluctuations and risks, or the affected site may temporarily or permanently cease operations. If we are unable to replace an expired distributed generation PPA with an acceptable new contract, we may be required to remove the renewable energy facility from the site or, alternatively, we may have to sell the assets, but the sale price may not be sufficient to replace the revenue previously generated by the renewable energy facility.

For some of our PPAs, the net amount paid by our PPA counterparties is impacted by wholesale prices at a market hub location different from the location of our renewable site. Systemic shortfalls and disruptions in transmission capacity can cause congestion between the two locations, which along with other factors, can cause price disparity between the market hub and site. This price disparity, known as basis risk, can be significant at times. We attempt to mitigate basis risk where possible, but hedging instruments are often not economically feasible or available in the quantities that we require. Basis risk cannot be entirely eliminated and can adversely affect our financial condition and results of operations.

Our non-utility renewable energy facilities are exposed to risks through participation in various regional power markets. Our ability to acquire new non-utility renewable energy facilities or generate revenue from existing facilities depends on having interconnection arrangements with transmission providers and power markets along with a reliable grid. We cannot predict whether transmission facilities will be expanded in specific markets to accommodate or increase competitive access to those markets. If a transmission network to which one or more of our facilities is connected experiences down time for system emergencies, force majeure, safety, reliability, maintenance or other operational reasons, we may lose revenues and PTCs and be exposed to non-performance penalties and claims from our customers. Curtailment of our non-utility renewable energy facilities may result in a reduced return on our investments, and we may not be compensated for lost energy and ancillary services. As members of these RTOs, we are also subject to certain additional risks, including the allocation of losses among existing members caused by unreimbursed defaults of other participants in these markets and resolution of complaint cases seeking refunds of revenues previously earned by members of these markets. Existing, new, or changed rules of these RTOs could result in significant additional fees and increased costs for participation, including the cost of transmission facilities built by others due to changes in transmission rate design. In addition, these RTOs may assess costs resulting from improved transmission reliability, reduced transmission congestion, and firm transmission rights.

We are a holding company and rely on the earnings of our subsidiaries to meet our financial obligations.

As a holding company with no operations of our own, our ability to meet our financial obligations including, but not limited to, debt service, taxes, and other expenses, as well as pay dividends on our common stock, is dependent upon the ability of our subsidiaries to pay amounts to us, whether through dividends or other payments. Our subsidiaries are separate legal entities that are not required to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to pay amounts to us depends on their earnings, cash flows, capital requirements, and general financial condition, as well as regulatory limitations. Prior to distributing cash to us, our subsidiaries have financial obligations that must be satisfied, including, among others, debt service and preferred stock dividends. In addition, each subsidiary's ability to pay amounts to us depends on any statutory, regulatory, and/or contractual restrictions and limitations applicable to such subsidiary, which may include requirements to maintain specified levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

We may fail to attract and retain an appropriately qualified workforce.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

Our counterparties may fail to meet their obligations, including obligations under power purchase, natural gas supply, natural gas pipeline capacity, and transportation agreements.

We are exposed to the risk that counterparties to various arrangements who owe us money, electricity, natural gas, or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform or if capacity is inadequate, we may be required to replace the underlying commitment at current market prices or we may be unable to meet all of our customers' electric and natural gas requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, and our results of operations, financial position, or liquidity could be adversely affected.

We have entered into several power purchase, natural gas supply, natural gas pipeline capacity, and transportation agreements with non-affiliated companies. Revenues are dependent on the continued performance by the counterparties of their obligations under these agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more counterparties could fail to perform their obligations. If this were to occur, we generally would expect that any operating and other costs that were initially allocated to a defaulting customer's power purchase, natural gas supply, natural gas pipeline capacity, or transportation agreement would be reallocated among our retail customers. To the extent these costs are not allowed to be reallocated by our regulators or there is any regulatory delay in adjusting rates, a counterparty default under these agreements could have a negative impact on our results of operations and cash flows.

Risks Related to Economic and Market Volatility

Our business is dependent on our ability to successfully access credit and capital markets on competitive terms and rates.

We rely on access to credit and capital markets to support our capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. In addition, we rely on committed bank credit agreements as back-up liquidity, which allows us to access the low cost commercial paper markets. The availability of credit depends upon the ability of banks providing commitments under the facility to provide funds when their obligations to do so arise. Systemic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the credit agreements.

Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, on competitive terms and rates. An increase in interest rates may adversely affect our results of operations and the ability of our regulated subsidiaries to earn their approved rates of return. High interest rates may also impair our ability to cost-effectively finance capital expenditures and to refinance maturing debt.

Our access to the credit and capital markets could be limited, or our cost of capital significantly increased, due to any of the following risks and uncertainties:

- A rating downgrade;
- Failure to comply with debt covenants;
- An economic downturn or uncertainty;
- Prevailing market conditions and rules;
- Political tensions, including civil unrest and election volatility;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- Changes in investment criteria of institutional investors or banks;
- War or the threat of war;
- Growth in AFUDC during periods of significant construction; and
- The overall health and view of the utility and financial institution industries.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, and financial condition, and could limit our ability to sustain and/or increase our current common stock dividend level.

A downgrade in our credit ratings could negatively affect our ability to access capital at reasonable costs and/or require the posting of collateral.

There are a number of factors that impact our credit ratings, including, but not limited to, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We could experience a downgrade in ratings if the rating agencies determine that our level of business or financial risk, or that of any of our utilities or the utility industry, has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings. Any downgrade by the rating agencies could increase borrowing costs under certain existing credit facilities or future financings, decrease funding sources, limit the availability of adequate credit support for our operations, and trigger collateral requirements in various contracts.

The fluctuation in demand for certain commodities and their respective prices could negatively impact our operations.

Our operating and liquidity requirements are impacted by changes in the forward and current market prices of natural gas, coal, electricity, renewable energy credits, and ancillary services.

Our electric utilities burn natural gas in several of their electric generation plants and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. The cost of natural gas may increase because of disruptions in the supply of natural gas due to a curtailment in production or distribution, international market conditions, the demand for natural gas, and the availability of shale gas and potential regulations and/or other government action affecting its accessibility. Our electric utilities also burn coal at certain of their electric generation facilities. We may be obligated to pay for coal deliveries under our contracts even if our coal-fired generating facilities do not operate enough to fully utilize the amounts of coal covered by the contracts.

For Wisconsin retail electric customers, our utilities bear the risk for the recovery of fuel and purchased power costs within a symmetrical 2% fuel tolerance band compared to the forecast of fuel and purchased power costs established in their respective rate structures. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers and our wholesale electric customers. Our natural gas utilities receive dollar-for-dollar recovery of prudently incurred natural gas costs from their natural gas customers.

Changes in the demand for commodities and their respective prices could result in:

- Higher working capital requirements, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;
- Reduced profitability to the extent that lower revenues, higher fuel costs, increased bad debt, and higher interest expense are not recovered through rates;
- Higher rates charged to our customers, which could impact our competitive position;
- Reduced demand for energy, which could impact revenues and operating expenses;
- Reduced growth prospects from renewable energy projects related to lower cost alternative energy sources and a limited number of purchasers of electricity; and
- Shutting down of generation facilities if the cost of generation exceeds the market price for electricity.

We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

We own and operate several coal-fired electric generating units. Although we generally carry sufficient coal inventory at our generating facilities to protect against an interruption or decline in supply, there can be no assurance that the inventory levels will be adequate. While we have coal supply and transportation contracts in place, we cannot assure that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us or that we will be able to take delivery of all the coal volume contracted for. Coal deliveries may occasionally be restricted because of rail congestion and maintenance, derailments, weather, public health crises, and supplier financial hardship as a result of decreased demand for coal. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices or we may be forced to reduce generation at our coal-fired units, which could lead to increased fuel costs. The increase in fuel costs could result in either reduced margins on net sales into the MISO Energy Markets, a reduction in the volume of net sales into the MISO Energy Markets, and/or an increase in net power purchases in the MISO Energy Markets. There is no guarantee that we would be able to fully recover any increased costs in rates or that recovery would not otherwise be delayed, either of which could adversely affect our results of operations and cash flows.

Our use of derivative contracts could result in financial losses.

We use derivative instruments such as swaps, options, futures, and forwards to manage commodity price exposure. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, although the hedging programs of our utilities must be approved by the various state commissions, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments can involve management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Restructuring in the regulated energy industry and competition in the retail and wholesale markets could have a negative impact on our business and revenues.

The regulated energy industry continues to experience significant structural changes. Deregulation or other changes in law in the states where we serve our customers could allow third-party suppliers to contract directly with customers for their natural gas and electric supply requirements. Increased competition in these markets could have a material adverse financial impact on us.

Certain jurisdictions in which we operate, including Michigan and Illinois, have adopted retail choice. Under Michigan law, our retail electric customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The iron ore mine located in the Upper Peninsula of Michigan is excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer. Although Illinois has adopted retail choice, there is currently little or no impact on the net income of our Illinois utilities as they still earn a distribution charge for transporting the natural gas for these customers. It is uncertain whether retail choice might be implemented in Wisconsin or Minnesota.

The FERC continues to support the existing RTOs that affect the structure of the wholesale market within these RTOs. In connection with its status as a FERC-approved RTO, MISO implemented bid-based energy markets that are part of the MISO Energy Markets. MISO also implemented an ancillary services market for operating reserves that schedules energy and ancillary services at the same time as part of the energy market. These market designs have the potential to increase costs related to transmission, inefficient generation dispatching, participation in the MISO Energy Markets, and estimated payment settlements.

The FERC rules related to transmission are designed to facilitate competition in the wholesale electricity markets among regulated utilities, non-utility generators, wholesale power marketers, and brokers by providing greater flexibility and more choices to wholesale customers, including initiatives designed to encourage the integration of renewable sources of supply. In addition, along with transactions contemplating physical delivery of energy, financial laws and regulations impact hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges, as well as over-the-counter. Technology changes in the power and fuel industries also have significant impacts on wholesale transactions and related costs. We currently cannot predict the impact of these and other developments or the effect of changes in levels of wholesale supply and demand, which are driven by factors beyond our control.

Volatility in the securities markets, interest rates, changes in assumptions, market conditions, and other factors may impact the performance of our benefit plan holdings and other investment funds.

We have significant obligations related to pension and OPEB plans. If we are unable to successfully manage our benefit plan assets and medical costs, our cash flows, financial condition, or results of operations could be adversely impacted. Our cost of providing these plans is dependent upon a number of factors, including actual plan experience, changes made to the plans, and assumptions concerning the future. Types of assumptions include earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation, estimated withdrawals by retirees, and our required or voluntary contributions to the plans. Plan assets are subject to market fluctuations and may yield returns that fall below projected return rates. In addition, medical costs for both active and retired employees may increase at a rate that is significantly higher than we currently anticipate. Our funding requirements could be impacted by a decline in the market value of plan assets, changes in interest rates, changes in demographics (including the number of retirements), or changes in life expectancy assumptions.

In addition, we maintain rabbi trusts to fund our deferred compensation plans and other investments funds, including our clean energy funds, which from time to time, hold equity and debt investments that are subject to market fluctuations. Decreases in investment performance of these assets could materially adversely affect our results of operations, cash flows, and financial condition.

General Risks

We have recorded goodwill and other long-lived assets, including intangible assets, which could become impaired.

We assess goodwill for impairment on an annual basis or whenever events or circumstances occur that would more than likely indicate that the carrying amount of our reporting unit's net assets exceeds the reporting unit's fair value. Other long-lived assets, including intangible assets, are evaluated for impairment on an annual basis or whenever events or circumstances occur that indicate that an asset's carrying value may not be recoverable. If goodwill or other long-lived assets are deemed to be impaired, we may be required to incur a non-cash charge to earnings that could materially adversely affect our results of operations.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, could be affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers and our contractors that are required to acquire and maintain insurance for our benefit. Insurance coverage may not continue to be available at all or at rates or terms similar to those presently available to us. In addition, our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Our Board of Directors is responsible for general oversight of our risk environment and associated management policies and practices. The Board of Directors has delegated to its AOC the responsibility for oversight of our major risk categories and exposures, including with respect to cybersecurity, and management's processes to monitor and control them. The AOC meets regularly throughout the year and receives and reviews various risk management reports about IT/OT cybersecurity, data security, and physical security risks, and discusses these matters with appropriate management and other personnel. The CEO and CAO regularly report to the AOC and the Board of Directors about cybersecurity matters and risks as well as the adequacy and effectiveness of the cybersecurity risk management program.

To foster an enterprise-wide approach to risk management, we have established an ERSC chaired by our CEO and comprised of a cross-functional group of senior leaders from across our organization. The ERSC regularly reviews key risk areas and oversees the development and implementation of effective compliance and risk management practices, including the use of internal and external audits. Our Board of Directors and the AOC receive reports regarding the same. Governance of our cybersecurity risk management program is overseen by the ERSC, along with steering committees for information security, operational technology security, third-party vendor security controls, Sarbanes-Oxley security controls, and North American Electric Reliability Corporation Critical Infrastructure Protection compliance.

Our CAO is responsible for enterprise-wide information technology services and cybersecurity system strategy. In this capacity, the CAO oversees the cybersecurity risk management program, which is maintained and implemented by the Enterprise Security Director. Our CAO has 26 years of experience at the company, during which time she has held a number of management and leadership positions, including Chief Information Officer, through which she has developed expertise in our IT/OT cybersecurity, data security, and physical security environment and risk profile.

The Enterprise Security Director, in collaboration with her team, is responsible for IT/OT cybersecurity, data security, and physical security. The Enterprise Security Director identifies, evaluates, and facilitates mitigation of cyber, data, and physical security risks and reports on cybersecurity matters and risks to the ERSC and the AOC. Our Enterprise Security Director has over 28 years of experience in IT/OT cybersecurity, data security and physical security, and is a certified information system security professional. She is also a member of numerous state and national cybersecurity organizations.

Cybersecurity Risk Management Program

Our cybersecurity-related risks are managed through monitoring, defense and response tools, audits and assessments of the program's effectiveness, industry collaboration, and employee training and awareness. Our cybersecurity risk management program utilizes the cybersecurity framework and maturity models from the National Institute of Standards and Technology and the DOE to continually assess its maturity. This includes regular internal security audits and vulnerability assessments, as well as regular engagement with third-party security experts for external assessments of our security controls, including technical, physical, and social aspects. To better comprehend the scope and magnitude of any active threats to our industry and nation and their potential impact on our IT/OT systems, we communicate with other utility companies, government agencies, and other sectors of the economy concerning cybersecurity incidents. All employees are required to complete training annually regarding information security and acceptable use of corporate electronic resources. Annual role-based cybersecurity training as well as ongoing participation in a corporate phishing campaign program, is also required of employees and contractors. In addition, as part of the cybersecurity program, we have established controls and procedures to assess the adequacy of controls in place at third-party vendors to protect corporate information, including restricted and confidential restricted information we provide to third-party vendors, their employees, or authorized agents. These third-party vendors are also subject to a background investigation prior to being granted physical or electronic access to the company's private property, or physical access to customer premises on behalf of the company.

As part of the cybersecurity program, we have adopted a cybersecurity incident response plan (the "Plan") designed to identify, evaluate, respond to, and resolve cybersecurity incidents impacting IT/OT systems. Pursuant to the terms of the Plan, we have established a CSIRT Steering Committee which includes, among others, the Chief Financial Officer, CAO, and the Enterprise Security Director. The CSIRT Steering Committee is responsible for overseeing and implementing the Plan in the event of a cybersecurity threat or incident and provides updates regarding the status of the response to senior management, including the CEO, who provides updates and reports regarding cybersecurity incidents to the AOC and/or the Board of Directors at regularly scheduled meetings or more frequently, as needed.

In response to an identified cybersecurity incident, or as it deems appropriate, the CSIRT Steering Committee will assemble and oversee a CSIRT, comprised of appropriate personnel and subject matter experts depending on the scope and severity of the incident, relevant or impacted business units and entities, and type of information or systems potentially compromised by the cybersecurity incident. When assembled, the CSIRT is responsible for developing and implementing an overall response strategy to contain, control, and remediate the cybersecurity incident, including securing affected systems and/or information, mitigating harmful effects of the incident, preventing further compromises, and communicating information to affected parties, regulatory agencies and law enforcement, as necessary. The CSIRT may seek assistance from or engage external support providers including legal counsel, outside technology or forensic experts, investigation service providers, and others, as appropriate, to assist in the response to the incident, based on its nature and scope. Pursuant to the Plan and at the direction of the CAO, the Enterprise Security Director will conduct a post-incident remediation analysis and report findings to the CSIRT Steering Committee. The Plan is tested and reviewed at least annually.

We have been subject to attempted cybersecurity attacks from time to time, and will likely continue to be subject to such attempted attacks; however, these prior attacks have not had a material impact on our system or business operations. For information about cybersecurity risks to our business, see Item 1A. Risk Factors and the risk factor titled "Our operations are subject to risks beyond our control, including but not limited to, cybersecurity intrusions, terrorist or other physical attacks, acts of war, or unauthorized access to personally identifiable information."

ITEM 2. PROPERTIES

We own our principal properties outright. However, the major portion of our electric utility distribution lines, steam utility distribution mains, and natural gas utility distribution mains and services are located on or under streets and highways, on land owned by others, and are generally subject to granted easements, consents, or permits.

A. REGULATED

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2025:

Name	Location	Fuel	Number of Generating Units	Capacity In MW [(1)]
Natural gas-fired plants				
PWGS	Port Washington, WI	Natural Gas	2	1,210 [(3)]
Fox Energy Center	Wrightstown, WI	Natural Gas	3	579
Concord Generating Station	Watertown, WI	Natural Gas/Oil	4	367
Paris	Union Grove, WI	Natural Gas/Oil	4	360
VAPP	Milwaukee, WI	Natural Gas	2	278
Germantown Power Plant	Germantown, WI	Natural Gas/Oil	5	261
Whitewater	Whitewater, WI	Natural Gas/Oil	1	234
West Riverside	Beloit, WI	Natural Gas	1	190 [(2)]
De Pere Energy Center	De Pere, WI	Natural Gas/Oil	1	170
West Marinette Power Plant	Marinette, WI	Natural Gas	3	149
Weston	Rothschild, WI	Natural Gas	7	130
F.D. Kuester Generating Station	Negaunee, MI	Natural Gas	7	128
Pulliam	Green Bay, WI	Natural Gas	1	82
A.J. Mihm Generating Station	Baraga, MI	Natural Gas	3	55
Total natural gas-fired plants			44	4,193
Coal-fired plants				
ERGS	Oak Creek, WI	Coal	2	1,083 [(2) (3)]
Weston	Rothschild, WI	Coal	2	699 [(2) (7)]
OCPP	Oak Creek, WI	Coal	2	607 [(7)]
Columbia	Portage, WI	Coal	2	306 [(2)]
Total coal-fired plants			8	2,695
Wind facilities				
Glacier Hills Wind Park	Cambria, WI	Wind	90	162
Blue Sky Green Field Wind Park	Fond du Lac, WI	Wind	88	145
Crane Creek Wind Park	Howard County, IA	Wind	66	99
Red Barn	Grant County, WI	Wind	28	82 [(2)]
Forward Wind	Fond du Lac County, WI	Wind	86	62 [(2)]
Montfort Wind Energy Center	Montfort, WI	Wind	20	30
Total wind facilities			378	580
Solar facilities				
Darien	Rock and Walworth counties, WI	Solar	65	225 [(2)]
Paris	Kenosha County, WI	Solar	53	180 [(2)]
Two Creeks	Manitowoc County, WI	Solar	48	100 [(2)]
Badger Hollow I	Iowa County, WI	Solar	41	100 [(2)]
Badger Hollow II	Iowa County, WI	Solar	40	100 [(2)]
DER Facilities (5 in number)	Wisconsin	Solar	15	38 [(8)]
Solar Now	Wisconsin	Solar	28	30
Total solar facilities			290	773
Other renewable facilities				
Hydro plants (26 in number)	WI and MI	Hydro	80	88 [(4) (5)]
Rothschild	Rothschild, WI	Biomass	1	46 [(6)]
Total other renewable facilities			81	134
Total electric generation facilities			801	8,375

(1) Capacity for our electric generation facilities, other than wind and solar generating facilities, is based on rated capacity, which is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. Values are

primarily based on the net dependable expected capacity ratings for summer 2026 established by tests and may change slightly from year to year. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand. Capacity for wind generating facilities is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds. Capacity for solar generating facilities is based on nameplate capacity, which is the maximum output that a generator should produce at continuous full power.

(2) Our subsidiaries jointly own these facilities with various other unaffiliated entities. The capacity indicated for each of these units is equal to our subsidiaries' portion of total plant capacity based on its percent of ownership. See Note 8, Jointly-Owned Utility Facilities, for more information on our ownership interests.

(3) These facilities are part of the Company's non-utility energy infrastructure segment. See B. Non-Utility Energy Infrastructure Segment below.

(4) All of our hydroelectric facilities follow FERC guidelines and/or regulations.

(5) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50.0% ownership interest in WRPC and is entitled to 50.0% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock and Petenwell is 7.0 MWs and 10.3 MWs, respectively.

(6) WE has a biomass power plant that uses wood waste and wood shavings to produce electric power as well as steam to support the paper mill's operations. Fuel for the power plant is supplied by both the paper mill and through contracts with biomass suppliers. The plant also has the ability to burn natural gas if wood waste and wood shavings are not available.

(7) We expect to retire approximately 900 MWs of additional coal-fired generation, which includes the planned retirements of OCPP Units 7-8 and Weston Unit 3.

(8) DER facilities are distribution system interconnected solar projects that are typically 5-10 MWs each.

As of December 31, 2025, we operated approximately 35,200 miles of overhead distribution lines and approximately 37,600 miles of underground distribution cable, as well as approximately 420 electric distribution substations and approximately 649,500 line transformers.

Battery Energy Storage Systems

We also own 99 MWs of BESS at Paris located in Kenosha County, WI which was completed in June 2025.

Natural Gas Facilities

At December 31, 2025, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 47,200 miles of natural gas distribution mains,
- Approximately 1,300 miles of natural gas transmission mains,
- Approximately 2.4 million natural gas lateral services,
- Approximately 510 natural gas distribution and transmission gate stations,
- Approximately 67.0 Bcf of working gas capacities in underground natural gas storage fields:
    - Bluewater, 27.6 Bcf of fields located in southeastern Michigan,
    - Manlove, a 36.5 Bcf field located in central Illinois,
    - Partello, a 2.9 Bcf field located in southern Michigan,
- A 2.0 Bcf LNG plant located in central Illinois,
- Two 1.0 Bcf LNG plants located in southern Wisconsin,
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquefied petroleum gas located in Illinois, and
- LNG storage plants, located in Wisconsin, with a total send-out capability of 273,600 Dth per day.

Our natural gas distribution and gas storage systems included distribution and transmission mains connected to the pipeline transmission systems of Alliance Pipeline, ANR Pipeline Company, Centra Pipelines, Consumers Energy, DTE Gas Company, Enbridge Gas Inc., Great Lakes Transmission Company, Guardian Pipeline L.L.C., Interstate Power and Light Company, Kinder Morgan Illinois Pipeline, Midwestern Gas Pipeline Company, Natural Gas Pipeline Company of America, Nicor Gas, Northern Border Pipeline Company, Northern Natural Gas Company, Northwest Gas of Cottonwood County, LLC, Northwestern Energy, Panhandle Gas Transmission, SEMCO, Trunkline Gas Pipeline, Vector Pipeline Company, and Viking Gas Transmission. Our LNG storage plants convert and store, in liquefied form, natural gas received during periods of low consumption.

We also own office buildings, natural gas regulating and metering stations, and major service centers, including garage and warehouse facilities, in certain communities we serve. Where distribution lines and services and natural gas distribution mains and services occupy private property, we have in some, but not all instances, obtained consents, permits, or easements for these installations from the apparent owners or those in possession of those properties, generally without an examination of ownership records or title.

Steam Facilities

As of December 31, 2025, the steam system supplied by the VAPP consisted of approximately 40 miles of both high pressure and low pressure steam piping, approximately four miles of walkable tunnels, and other pressure regulating equipment.

General

Substantially all of PGL's and NSG's properties are subject to the lien of the respective company's mortgage indenture for the benefit of bondholders.

B. NON-UTILITY ENERGY INFRASTRUCTURE SEGMENT

The non-utility energy infrastructure segment includes We Power, Bluewater, and WECI. We Power and Bluewater are considered non-utility energy infrastructure operations, however, their facilities are shown in the regulated section. We Power owns and leases its share of the ERGS units and both PWGS units to WE under long-term leases. Bluewater provides natural gas storage and hub services primarily to WE, WPS, and WG. WECI has ownership interests in eight wind and four solar generating facilities. For more information on recent renewable facility acquisitions, see Note 2, Acquisitions.

The following table summarizes information on WECI's renewable generating facilities as of December 31, 2025:

Name	Location	Ownership Percentage (%) [1]	Number of Generating Units	Nameplate Capacity In MW [2]
Renewable generating facilities				
Delilah I	Lamar, Franklin, Hopkins and Red River Counties, Texas	90.0 %	410	300.0
Thunderhead	Antelope and Wheeler Counties, Nebraska	90.0 %	108	299.3
Blooming Grove	McLean County, Illinois	90.0 %	94	260.9
Sapphire Sky	McLean County, Illinois	90.0 %	64	259.8
Hardin III	Hardin County, Ohio	90.0 %	350	250.0
Maple Flats	Clay County, Illinois	90.0 %	343	250.0
Samson I	Lamar, Franklin, Hopkins and Red River Counties, Texas	90.0 %	340	250.0
Upstream	Antelope County, Nebraska	90.0 %	81	202.5
Jayhawk	Bourbon and Crawford Counties, Kansas	90.0 %	70	197.4
Tatanka Ridge	Deuel County, South Dakota	85.7 %	56	154.8
Bishop Hill III	Henry County, Illinois	90.0 %	53	132.1
Coyote Ridge	Brookings County, South Dakota	82.6 %	39	97.4
Total renewable generating facilities			2,008	2,654.2

(1) Invenergy Services LLC operates these renewable facilities.

(2) Nameplate capacity is the amount of energy a source should produce under optimal conditions, such as optimal wind speeds or solar irradiance.

ITEM 3. LEGAL PROCEEDINGS

In addition to those legal proceedings discussed in Note 24, Commitments and Contingencies, and Note 26, Regulatory Environment, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these additional legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material impact on our financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The names, ages, and positions of our executive officers are listed below along with their business experience during the past five years. All officers are appointed until their resignation, death, or removal pursuant to our Bylaws. There are no family relationships among these officers, nor is there any agreement or understanding between any officer and any other person pursuant to which the officer was selected.

Joshua M. Erickson. Age 53.
- WBS (a centralized service company of WEC Energy Group) – Assistant Corporate Secretary since January 2025. Vice President and Deputy General Counsel since August 2021. Director-Legal Services – Corporate and Finance from June 2015 through July 2021.
- WE — Assistant Corporate Secretary since January 2025.

Robert M. Garvin. Age 59.
- WEC Energy Group — Executive Vice President - External Affairs since June 2015.
- WBS (a centralized service company of WEC Energy Group) — Executive Vice President - External Affairs since January 2019.

William J. Guc. Age 56.
- WEC Energy Group — Controller since October 2015. Vice President since June 2015.
- WE — Vice President and Controller since October 2015. Assistant Corporate Secretary from January 2020 to December 2024.

Michael W. Hooper. Age 52.
- WEC Energy Group — Executive Vice President and Chief Operating Officer since May 2025.
- WE — President since April 2024. Director since April 2024.
- NiSource, Inc. — Senior Vice President and President, NIPSCO from May 2020 to March 2024. NiSource is a public utility holding company whose operating subsidiaries provide natural gas and electric service to customers across Indiana, Kentucky, Maryland, Ohio, Pennsylvania, and Virginia. NIPSCO is a public natural gas and electric utility company in Indiana.

Margaret C. Kelsey. Age 61.
- WEC Energy Group — Executive Vice President, Corporate Secretary and General Counsel since January 2018.
- WE — Executive Vice President, Corporate Secretary and General Counsel since January 2018. Director since January 2018.

Daniel P. Krueger. Age 60.
- WBS (a centralized service company of WEC Energy Group) — Executive Vice President - Infrastructure and Generation Planning since October 2023. Executive Vice President from January 2019 to October 2023.

Scott J. Lauber. Age 60.
- WEC Energy Group — President and Chief Executive Officer since February 2022. Senior Executive Vice President and Chief Operating Officer from June 2020 to January 2022. Director since February 2022.
- WE — Chairman of the Board and Chief Executive Officer since February 2022. President from January 2022 to April 2024. Executive Vice President from June 2020 to December 2021. Director since April 2016.

Xia Liu. Age 56.
- WEC Energy Group — Executive Vice President and Chief Financial Officer since June 2020.
- WE — Executive Vice President and Chief Financial Officer since June 2020. Director since June 2020.

Molly A. Mulroy. Age 50.
- WBS (a centralized service company of WEC Energy Group) – Executive Vice President and Chief Administrative Officer since August 2021. Vice President and Chief Information Officer from January 2019 through July 2021. Director since November 2021.

Anthony L. Reese. Age 44.
- WEC Energy Group — Vice President and Treasurer since October 2019.
- WE — Vice President and Treasurer since October 2019.

Mary Beth Straka. Age 61.
- WEC Energy Group — Senior Vice President - Corporate Communications and Investor Relations since June 2015.

Certain executive officers also hold officer and/or director positions at WEC Energy Group's other significant subsidiaries.

PART II

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

Number of Common Shareholders

As of January 31, 2026, based upon the number of WEC Energy Group shareholder accounts (including accounts in our stock purchase and dividend reinvestment plan), we had approximately 32,000 registered shareholders.

Common Stock Listing and Trading

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC."

Common Stock Dividends of WEC Energy Group, Inc.

We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition, and other requirements. For more information on our dividends, including restrictions on the ability of our subsidiaries to pay us dividends, see Note 11, Common Equity.

ITEM 6. RESERVED

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

CORPORATE DEVELOPMENTS

Introduction

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in ATC (a for-profit electric transmission company regulated by the FERC and certain state regulatory commissions), and non-utility energy infrastructure operations through We Power (which owns generation assets in Wisconsin that it leases to WE), Bluewater (which owns underground natural gas storage facilities in Michigan), and WECI (which holds ownership interests in several renewable generating facilities).

Corporate Strategy

We are working to build and sustain long-term value for our shareholders and customers by supporting economic growth in our region while focusing on the fundamentals of our business: reliability, operating efficiency, financial discipline, environmental stewardship, exceptional customer care, and safety. Our capital plan provides a roadmap for us to achieve this goal. It is a plan premised upon maintaining superior reliability, delivering savings for customers, and growing our investment in the future of energy.

Throughout our strategic planning process, we take into account important developments, risks and opportunities, including new technologies, customer preferences and affordability, energy resiliency efforts, and sustainability.

Supporting Economic Growth Within Our Communities

Economic growth continues in our Wisconsin service territories. Companies are investing in major projects, including data centers and modern manufacturing facilities. We anticipate electric demand growth in the years ahead from these economic developments. Microsoft has announced plans to invest over $20 billion in data centers in southern Wisconsin over the next several years, and we expect up to 2.6 GWs of load growth in the Milwaukee-to-Chicago corridor through 2030. Additionally, Vantage Data Centers plans to develop a large data center campus in Port Washington that is forecasted to add 1.3 GWs of demand through 2030. This site has the potential to add an incremental 2.2 GWs, for a total of up to 3.5 GWs over time. We are working closely with these large customers to provide power to meet this substantial projected demand. In 2025, we submitted a proposal to the PSCW for new VLC and Bespoke Resources tariffs. The proposed tariffs specifically address the unique needs of VLCs while protecting our other customers and shareholders. See Note 26, Regulatory Environment, for more information on the VLC and Bespoke Resources tariffs.

To meet the forecasted electric demand growth in the years ahead, greater capacity will be required to provide affordable, reliable, and clean energy for our communities. Our capital plan addresses that demand with a range of planned investments in natural gas-fired generation, renewables, and battery storage. We plan on investing approximately $5.4 billion from 2026 to 2030 in a combination of efficient natural gas-fired generation, including:

- 3,300 MWs of CTs (we plan on constructing a new natural gas lateral pipeline to support the CTs planned at our OCPP site); and
- 180 MWs of RICE natural gas-fueled generation.

We expect to invest approximately $12.6 billion from 2026 to 2030 in regulated renewable energy in Wisconsin. Our plan is to build and own zero-carbon-emitting renewable generation facilities that are anticipated to include the following investments:

- 3,850 MWs of utility-scale solar;
- 2,130 MWs of battery storage; and
- 555 MWs of wind.

For more details on the projects discussed above, see Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

Our capital plan also reflects the planned retirement of our older, fossil-fueled generation, which we expect to replace with the natural gas-fired generation and zero-carbon-emitting renewables discussed above. These retirements are intended to address compliance with EPA regulations established under the CAA, as well as contribute to meeting our goal to reduce CO_2 emissions from our electric generation. Our long-term goal is to achieve net carbon neutral electric generation by the end of 2050. We expect to achieve this goal by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. We expect to use coal only as a backup fuel by the end of 2030 and to be in a position to eliminate coal as an energy source by the end of 2032.

As part of our path toward this goal, we have started implementing co-firing with natural gas at the ERGS coal-fired units and at Weston Unit 4. Additionally, we have retired nearly 2,500 MWs of fossil-fueled generation since the beginning of 2018, which includes the retirement of OCPP Units 5 and 6 in May 2024, the 2019 retirement of the PIPP, and the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit. We expect to retire approximately 900 MWs of additional coal-fired generation by the end of 2031, which includes the planned retirements of OCPP Units 7 and 8 and Weston Unit 3. In conjunction with our new capital plan, we and the other co-owners of Columbia Units 1 and 2 currently plan to continue coal operations at these units through at least 2029, and continue to evaluate the conversion of both units to natural gas. See Note 7, Property, Plant, and Equipment, for more information related to Columbia Units 1 and 2 and our planned power plant retirements.

When taken together, the retirements and new investments in natural gas generation and renewables should better balance our supply with our demand, while helping to address compliance and maintaining reliable, affordable energy for our customers.

We also continue to focus on methane emission reductions by improving and upgrading our natural gas distribution systems and using RNG throughout our natural gas utility systems. In 2023, we began transporting the output of local dairy farms onto our natural gas distribution systems in Wisconsin. The RNG supplied is replacing higher-emission methane from natural gas that would have entered our pipes. We currently have contracts in place for 2.1 Bcf of RNG.

Reliability

We have made significant reliability-related investments in recent years, and in accordance with our capital plan, expect to continue strengthening and modernizing our generation fleet, as well as our electric and natural gas distribution networks to further improve reliability.

Below are a few examples of the projects that are proposed, currently underway, or recently completed.

- The PSCW approved WE's request to construct an LNG facility with a storage capacity of two Bcf, which will be located on the OCPP site. In addition, the construction of additional LNG facilities in Wisconsin has been proposed as part of our capital plan and would provide another approximately four Bcf of natural gas supply. The LNG facilities are expected to reduce the likelihood of constraints on our natural gas distribution system during the highest demand days of winter.

- PGL had been working to replace old iron pipes and facilities in Chicago's natural gas delivery system with modern polyethylene pipes to reinforce the long-term safety and reliability of the system. In November 2023, the ICC ordered PGL to pause spending on these projects until the ICC completed a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level. In a limited-scope rehearing of this order, PGL was authorized spending for completion of projects that had started in 2023. In February 2025, the ICC issued an order setting expectations for PGL's prospective retirement of its aging natural gas infrastructure. The ICC directed us to focus on retiring all cast and ductile iron pipe that has a diameter of less than 36 inches by January 1, 2035. PGL is working to retire this cast and ductile iron pipe through its PRP. For more information, see Note 26, Regulatory Environment, and Factors Affecting Results, Liquidity, and Capital Resources - Regulatory, Legislative, and Legal Matters - Illinois Proceedings.

- Our capital plan includes $2.9 billion of investments in BESSs from 2026 to 2030, which are intended to capture excess power and release it during peak demand or when power is limited due to weather or other unexpected disruptions.

- Our utilities continue to upgrade their electric and natural gas distribution systems to enhance reliability and storm hardening.

We expect to spend approximately $7.1 billion and $4.7 billion on reliability related to natural gas and electric distribution projects, respectively, from 2026 to 2030, with continued investment over the next decade. For more details, see Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company and will continue to do so under our capital plan. For example, we are making progress on our advanced metering infrastructure program, replacing aging meter-reading equipment on both our network and customer property. An integrated system of smart meters, communication networks, and data management programs enables two-way communication between our utilities and our customers. This program reduces the manual effort for customer connections and enhances outage management capabilities.

Through our multiyear Energy Delivery Program, we are planning to implement capabilities and standard processes for customer service, natural gas and electric operations, work management, and field operations. This includes improvements to outage management, geographic information systems, and work and asset management systems, as well as the implementation of new capabilities through advanced distribution management systems.

We continue to focus on integrating the resources of all our businesses and improving our business processes to find the best and most efficient processes possible, including evaluating the use of AI tools. We expect these efforts to continue to drive operational efficiency and to put us in a position to effectively support plans for future growth.

Financial Discipline

A strong adherence to financial discipline is essential to meeting our earnings projections and maintaining a strong balance sheet, stable cash flows, a growing dividend, and quality credit ratings. We work to earn allowed rates of return through a focus on cost control and strategic investment.

Our planned investment focus from 2026 to 2030 is in our regulated utilities and our investment in ATC. We expect total capital expenditures for our regulated utility businesses to be approximately $33.4 billion from 2026 to 2030. In addition, we currently forecast that our share of ATC's projected capital expenditures over the next five years will be approximately $4.1 billion. For additional information regarding projects included in the $37.5 billion capital plan, see Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

We follow an asset management strategy that focuses on investing in and acquiring assets consistent with our strategic plans, as well as disposing of assets, including property, plants, equipment, and entire business units, that are no longer strategic to operations, are not performing as intended, or have an unacceptable risk profile. See Note 2, Acquisitions, and Note 3, Disposition, for additional information on our recent and pending transactions.

Exceptional Customer Care

Our approach is driven by an intense focus on delivering exceptional customer care every day. We strive to provide the best value for our customers by demonstrating personal responsibility for results, leveraging our capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations.

A multiyear effort is driving a standardized, seamless approach to digital customer service across our companies. We have moved all utilities to a common platform for all customer-facing self-service options. Using common systems and processes reduces costs, provides greater flexibility and enhances the consistent delivery of exceptional service to customers.

Safety

Safety is one of our core values and a critical component of our culture. We are committed to keeping our employees and the public safe through a comprehensive corporate safety program that focuses on employee engagement and elimination of at-risk behaviors. To further protect public safety, we monitor the integrity of our distribution systems, have emergency response and business continuity plans in place, and provide key safety information to customers, contractors, and first responders.

Under our "Target Zero" mission, we have an ultimate goal of zero incidents, accidents, and injuries. Management and union leadership work together to reinforce the Target Zero culture. We set annual goals for safety results as well as measurable leading indicators, in order to raise awareness of at-risk behaviors and situations and guide injury-prevention activities. All employees are encouraged to report unsafe conditions or incidents that could have led to an injury. Injuries and tasks with high levels of risk are assessed, and findings and best practices are shared across our companies.

Our corporate safety program provides a forum for addressing employee concerns, training employees and contractors on current safety standards, and recognizing those who demonstrate a safety focus.

RESULTS OF OPERATIONS

The following discussion and analysis of our Results of Operations includes comparisons of our results for the year ended December 31, 2025 with the year ended December 31, 2024. For a similar discussion that compares our results for the year ended December 31, 2024 with the year ended December 31, 2023, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations in Part II of our 2024 Annual Report on Form 10-K, which was filed with the SEC on February 21, 2025.

Consolidated Earnings

The following table compares our consolidated results, including favorable or better, "B," and unfavorable or worse, "W," variances:

	Year Ended December 31		
(in millions, except per share data)	**2025**	**2024**	**B (W)**
Wisconsin	**$ 1,054.8**	$ 863.1	$ 191.7
Illinois	**122.1**	252.1	(130.0)
Other states	**60.8**	54.5	6.3
Electric transmission	**147.6**	141.0	6.6
Non-utility energy infrastructure	**411.1**	380.8	30.3
Corporate and other	**(238.9)**	(164.3)	(74.6)
Net income attributed to common shareholders	**$ 1,557.5**	$ 1,527.2	$ 30.3
Diluted EPS	**$ 4.81**	$ 4.83	$ (0.02)

2025 Compared with 2024

Earnings increased $30.3 million during 2025, compared with 2024. The significant factors impacting the $30.3 million increase in earnings were:

- A $191.7 million increase in net income attributed to common shareholders at the Wisconsin segment, driven by higher margins from the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, higher retail sales volumes, and an increase in certain income tax benefits. These positive impacts were partially offset by higher operating expenses, largely due to increases in depreciation and amortization expense, costs related to our power plants, transmission expense, and expense related to our earnings sharing mechanisms. Lower other income, driven by a negative impact from the non-service components of our net periodic pension and OPEB costs, also partially offset the positive impacts to earnings. See Note 26, Regulatory Environment, for more information on the Wisconsin rate orders.

- A $30.3 million increase in net income attributed to common shareholders at the non-utility energy infrastructure segment, driven by an increase in PTCs from our non-utility renewable generating facilities related to the acquisition of additional renewable generation facilities in the fourth quarter of 2024 and the first quarter of 2025. This increase was partially offset by higher interest expense due to the issuance of long-term debt at WECI Energy Holding III in December 2024.

These increases in earnings were partially offset by:

- A $130.0 million decrease in net income attributed to common shareholders at the Illinois segment, driven by a $205.0 million pre-tax charge to income in 2025 due to PGL and NSG agreeing on the terms of a proposed settlement with the Illinois Attorney General that would resolve all open proceedings related to the UEA and QIP riders. Partially offsetting this decrease was a year-over-year positive impact from a $25.3 million pre-tax charge to income in 2024 related to the ICC's disallowance of certain capital costs in PGL's 2016 rider QIP reconciliation. See Note 26, Regulatory Environment, for more information.

- A $74.6 million increase in the net loss attributed to common shareholders at the corporate and other segment, driven by higher interest expense in 2025 and the year-over-year impact from the gain on debt extinguishment recorded in 2024. A net loss from our equity method investments in technology and energy-focused investment funds during 2025, compared to net earnings in 2024, also contributed to the higher net loss.

Non-GAAP Financial Measures

The discussions below address the contribution of each of our utility segments to net income attributed to common shareholders. The discussions include financial information prepared in accordance with GAAP, as well as utility margin, which is not a measure of financial performance under GAAP. Utility margin (operating revenues less fuel and purchased power costs and cost of natural gas sold) is a non-GAAP financial measure because it excludes certain operation and maintenance expenses applicable to revenues, as well as depreciation and amortization and property and revenue taxes.

We believe that utility margin provides a useful basis for evaluating utility operations since the majority of prudently incurred fuel and purchased power costs, as well as prudently incurred natural gas costs, are passed through to customers in current rates. As a result, management uses utility margin internally when assessing the operating performance of our utility segments as these measures exclude the majority of revenue fluctuations caused by changes in these expenses. Similarly, the presentation of utility margin herein is intended to provide supplemental information for investors regarding our operating performance.

Our utility margin may not be comparable to similar measures presented by other companies. Furthermore, this measure is not intended to replace gross margin as determined in accordance with GAAP as an indicator of operating performance. Each of our three utility segment discussions below include a table that provides the calculation of both gross margin as determined in accordance with GAAP and utility margin, as well as a reconciliation between the two measures.

Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders

The Wisconsin segment's contribution to net income attributed to common shareholders for the year ended December 31, 2025 was $1,054.8 million, representing a $191.7 million, or 22.2%, increase over the prior year. The higher earnings were driven by an increase in margins from the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, higher retail sales volumes, and an increase in certain income tax benefits. These positive impacts were partially offset by higher operating expenses, largely due to increases in depreciation and amortization expense, costs related to our power plants, transmission expense, and expense related to our earnings sharing mechanisms. Lower other income, driven by a negative impact from the non-service components of our net periodic pension and OPEB costs, also partially offset the positive impacts to earnings. See Note 26, Regulatory Environment, for more information on the Wisconsin rate orders.

	Year Ended December 31		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 7,295.5**	$ 6,330.5	$ 965.0
Operating expenses			
Cost of sales [(1)]	**2,546.4**	2,117.6	(428.8)
Other operation and maintenance	**1,737.9**	1,547.9	(190.0)
Depreciation and amortization	**1,008.1**	919.9	(88.2)
Property and revenue taxes	**178.7**	169.6	(9.1)
Operating income	**1,824.4**	1,575.5	248.9
Other income, net	**96.5**	146.6	(50.1)
Interest expense	**638.7**	637.3	(1.4)
Income before income taxes	**1,282.2**	1,084.8	197.4
Income tax expense	**226.2**	220.5	(5.7)
Preferred stock dividends of subsidiary	**1.2**	1.2	—
Net income attributed to common shareholders	**$ 1,054.8**	$ 863.1	$ 191.7

(1) Cost of sales includes fuel and purchased power and cost of natural gas sold.

The following table shows a breakdown of other operation and maintenance:

	Year Ended December 31		
(in millions)	**2025**	**2024**	**B (W)**
Operation and maintenance not included in line items below	**$ 753.9**	$ 659.6	$ (94.3)
Transmission [1]	**584.9**	543.3	(41.6)
Regulatory amortizations and other pass through expenses [2]	**231.8**	215.9	(15.9)
We Power [3]	**128.7**	131.4	2.7
Earnings sharing mechanisms [4]	**28.6**	(4.3)	(32.9)
Other	**10.0**	2.0	(8.0)
Total other operation and maintenance	**$ 1,737.9**	$ 1,547.9	$ (190.0)

[1] Represents transmission expense that our electric utilities are authorized to collect in rates. The PSCW has approved escrow accounting for ATC and MISO network transmission expenses for WE and WPS. As a result, WE and WPS defer as a regulatory asset or liability, the difference between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding. During 2025 and 2024, $618.5 million and $565.3 million, respectively, of costs were billed to our electric utilities by transmission providers.

[2] Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on net income.

[3] Represents costs associated with the We Power generation units, including operating and maintenance costs recognized by WE. During 2025 and 2024, $125.1 million and $115.8 million, respectively, of costs were billed to or incurred by WE related to the We Power generation units, with the difference in costs billed or incurred and expenses recognized, either deferred or deducted from the regulatory asset.

[4] Represents operation and maintenance associated with the earnings mechanisms we have in place. See Note 26, Regulatory Environment, for more information.

The following tables provide information on delivered sales volumes by customer class and weather statistics:

	Year Ended December 31		
Electric Sales Volumes ***(MWh - in thousands)***	**2025**	**2024**	**B (W)**
Customer class			
Residential	**11,411.0**	11,025.3	385.7
Small commercial and industrial [1]	**13,019.5**	12,815.8	203.7
Large commercial and industrial [1]	**12,061.3**	11,966.7	94.6
Other	**117.7**	125.1	(7.4)
Total retail [1]	**36,609.5**	35,932.9	676.6
Wholesale	**1,747.3**	1,648.2	99.1
Resale	**5,702.7**	5,863.1	(160.4)
Total sales in MWh [1]	**44,059.5**	43,444.2	615.3

[1] Includes distribution sales for customers who have purchased power from an alternative electric supplier in Michigan.

	Year Ended December 31		
Natural Gas Sales Volumes ***(Therms - in millions)***	**2025**	**2024**	**B (W)**
Customer class			
Residential	**1,125.8**	968.5	157.3
Commercial and industrial	**737.0**	625.2	111.8
Total retail	**1,862.8**	1,593.7	269.1
Transportation	**1,381.2**	1,316.5	64.7
Total sales in therms	**3,244.0**	2,910.2	333.8

Weather *(Degree Days)* [(1)]	Year Ended December 31 2025	2024	B (W)
WE and WG			
Heating (6,351 Normal)	**6,641**	5,190	28.0 %
Cooling (723 Normal)	**789**	831	(5.1)%
WPS			
Heating (7,210 Normal)	**7,217**	6,015	20.0 %
Cooling (580 Normal)	**653**	608	7.4 %
UMERC			
Heating (8,242 Normal)	**8,201**	7,190	14.1 %
Cooling (353 Normal)	**388**	317	22.4 %

(1) Normal degree days are based on a 20-year moving average of monthly temperature readings from National Oceanic and Atmospheric Administration weather stations within each company's respective service territories.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our Wisconsin segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See Non-GAAP Financial Measures above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

(in millions)	Year Ended December 31 2025	2024	B (W)
Electric revenues	**$ 5,547.4**	$ 4,921.6	$ 625.8
Natural gas revenues	**1,748.1**	1,408.9	339.2
Operating revenues	**7,295.5**	6,330.5	965.0
Operating expenses			
Fuel and purchased power	**(1,674.9)**	(1,455.7)	(219.2)
Cost of natural gas sold	**(871.5)**	(661.9)	(209.6)
Other operation and maintenance [(1)]	**(1,223.8)**	(1,095.1)	(128.7)
Depreciation and amortization	**(1,008.1)**	(919.9)	(88.2)
Property and revenue taxes	**(178.7)**	(169.6)	(9.1)
Gross margin (GAAP)	**2,338.5**	2,028.3	310.2
Other operation and maintenance [(1)]	**1,223.8**	1,095.1	128.7
Depreciation and amortization	**1,008.1**	919.9	88.2
Property and revenue taxes	**178.7**	169.6	9.1
Utility margin (non-GAAP)	**$ 4,749.1**	$ 4,212.9	$ 536.2

(1) Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include plant operating and maintenance expenses related to our generating units; costs associated with the We Power generating units; and transmission, distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) at the Wisconsin segment increased $310.2 million during 2025, compared with 2024, and utility margin (non-GAAP) increased $536.2 million during 2025, compared with 2024. Both measures were driven by:

- A $402.4 million increase in margins driven by the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025. See Note 26, Regulatory Environment, for more information.

- A $135.5 million increase in margins related to higher retail sales volumes, driven by the impact of favorable weather during 2025, compared with 2024. As measured by heating degree days, 2025 was 28.0% and 20.0% colder than 2024 in the Milwaukee area and Green Bay area, respectively. As measured by cooling degree days, 2025 was 7.4% warmer than 2024 in the WPS service area.

Additionally, the smaller increase in gross margin (GAAP) as compared with the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- An $88.2 million increase in depreciation and amortization expense;
- A $46.2 million increase in other operating and maintenance related to our power plants;
- A $41.6 million increase in transmission expense;
- A $32.2 million increase in electric and natural gas distribution expenses;
- A $10.0 million increase in expense related to the resolution of certain items in our rate orders; and
- A $9.1 million increase in property and revenues taxes.

Other Operating Expenses (includes other operation and maintenance, depreciation and amortization, and property and revenue taxes)

Other operating expenses at the Wisconsin segment increased $287.3 million during 2025, compared with 2024. The significant factors impacting the increase in other operating expenses were:

- An $88.2 million increase in depreciation and amortization expense, driven by assets being placed into service as we continue to execute on our capital plan.
- A $46.2 million increase in other operating and maintenance related to our power plants, driven by the resolution of certain items as a result of the December 2024 Wisconsin rate orders approved by the PSCW, as well as new renewable generation facilities placed in service during 2025.
- A $41.6 million increase in transmission expense as approved by the PSCW in our Wisconsin rate orders, effective January 1, 2025. See the notes under the other operation and maintenance table above for more information.
- A $32.9 million increase in expense related to the earnings sharing mechanisms in place at our Wisconsin utilities, as discussed in the notes under the other operation and maintenance table above. See Note 26, Regulatory Environment, for more information.
- A $32.2 million increase in electric and natural gas distribution expenses, driven by higher costs to maintain the distribution systems.
- A $15.9 million increase in regulatory amortizations and other pass through expenses, as discussed in the notes under the other operation and maintenance table above.
- A $12.4 million increase in expense driven by higher commitments made in 2025 to fund our charitable foundations.
- A $10.0 million increase in expense, driven by the resolution of certain items as a result of the December 2024 Wisconsin rate orders approved by the PSCW, as well as the October 2024 UMERC rate order approved by the MPSC.
- A $9.1 million increase in property and revenue taxes during 2025, compared with 2024, driven by a 2024 adjustment related to a sales tax audit at WE.
- A $6.2 million increase in environmental costs.

These increases in other operating expenses were partially offset by a $12.8 million decrease in benefit costs.

Other Income, Net

Other income, net at the Wisconsin segment decreased $50.1 million during 2025, compared with 2024, driven by an $83.6 million negative impact from the non-service components of our net periodic pension and OPEB costs. In accordance with our December

2024 PSCW rate orders, in 2025 we began amortizing our pension and OPEB costs that were previously deferred under escrow accounting. During 2025, we amortized $48.4 million of the previously deferred non-service costs as we are now collecting these costs in rates. See Note 20, Employee Benefits, for more information on our benefit costs. This decrease in other income, net was partially offset by a $39.5 million positive impact from higher AFUDC-Equity due to continued capital investment.

Interest Expense

Interest expense at the Wisconsin segment increased $1.4 million during 2025, compared with 2024. The increase was primarily due to the impact of long-term debt issuances in 2024 and 2025. Partially offsetting this increase was long-term debt maturities for WE, WPS, and WG in 2024 and 2025. See Note 14, Long-Term Debt, for more information. Also offsetting the increase was higher AFUDC-Debt due to continued capital investment, lower average short-term debt balances, and lower average short-term debt interest rates.

Income Tax Expense

Income tax expense at the Wisconsin segment increased $5.7 million during 2025, compared with 2024, driven by higher pre-tax income.

This increase in income tax expense was partially offset by:

- A $23.3 million increase in PTCs; and

- A $20.4 million increase in the benefit from the flow through of tax repairs in connection with the Wisconsin rate orders approved by the PSCW, effective January 1, 2025.

See Note 16, Income Taxes, for more information.

Illinois Segment Contribution to Net Income Attributed to Common Shareholders

The Illinois segment's contribution to net income attributed to common shareholders for the year ended December 31, 2025 was $122.1 million, representing a $130.0 million, or 51.6%, decrease from the prior year. The decrease was driven by a $205.0 million pre-tax charge to income in 2025 due to PGL and NSG agreeing on the terms of a proposed settlement with the Illinois Attorney General that would resolve all open proceedings related to the UEA and QIP riders. Partially offsetting this decrease was a year-over-year positive impact from a $25.3 million pre-tax charge to income in 2024 related to the ICC's disallowance of certain capital costs in PGL's 2016 rider QIP reconciliation. See Note 26, Regulatory Environment, for more information.

Since the majority of PGL and NSG customers use natural gas for heating, net income attributed to common shareholders at the Illinois segment is sensitive to weather and is generally higher during the winter months.

(in millions)	Year Ended December 31 2025	2024	B (W)
Operating revenues	**$ 1,683.6**	$ 1,602.4	$ 81.2
Operating expenses			
Cost of natural gas sold	**508.0**	376.7	(131.3)
Other operation and maintenance	**482.2**	461.5	(20.7)
Impairments	**130.0**	12.1	(117.9)
Depreciation and amortization	**259.7**	255.4	(4.3)
Property and revenue taxes	**55.5**	59.9	4.4
Operating income	**248.2**	436.8	(188.6)
Other income, net	**8.6**	7.6	1.0
Interest expense	**88.9**	94.7	5.8
Income before income taxes	**167.9**	349.7	(181.8)
Income tax expense	**45.8**	97.6	51.8
Net income attributed to common shareholders	**$ 122.1**	$ 252.1	$ (130.0)

The following table shows a breakdown of other operation and maintenance:

(in millions)	Year Ended December 31 2025	2024	B (W)
Operation and maintenance not included in the line items below	**$ 323.2**	$ 318.5	$ (4.7)
Riders [(1)]	**154.2**	139.7	(14.5)
Regulatory amortizations [(1)]	**2.8**	2.3	(0.5)
Other	**2.0**	1.0	(1.0)
Total other operation and maintenance	**$ 482.2**	$ 461.5	$ (20.7)

(1) These riders and regulatory amortizations are substantially offset in margins and therefore do not have a significant impact on net income.

The following tables provide information on delivered sales volumes by customer class and weather statistics:

Natural Gas Sales Volumes *(Therms - in millions)*	Year Ended December 31 2025	2024	B (W)
Customer Class			
Residential	**855.9**	745.4	110.5
Commercial and industrial	**317.6**	287.7	29.9
Total retail	**1,173.5**	1,033.1	140.4
Transportation	**775.1**	707.8	67.3
Total sales in therms	**1,948.6**	1,740.9	207.7

Weather *(Degree Days)* [(1)]	Year Ended December 31 2025	2024	B (W)
Heating (5,895 Normal)	**5,869**	4,848	21.1 %

(1) Normal heating degree days are based on a 12-year moving average of monthly temperature readings from National Oceanic and Atmospheric Administration weather stations throughout our Illinois service territories.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our Illinois segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See Non-GAAP Financial Measures above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

	Year Ended December 31		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 1,683.6**	$ 1,602.4	$ 81.2
Operating expenses			
Cost of natural gas sold	**(508.0)**	(376.7)	(131.3)
Other operation and maintenance [(1)]	**(233.6)**	(227.2)	(6.4)
Depreciation and amortization	**(259.7)**	(255.4)	(4.3)
Property and revenue taxes	**(55.5)**	(59.9)	4.4
Gross margin (GAAP)	**626.8**	683.2	(56.4)
Other operation and maintenance [(1)]	**233.6**	227.2	6.4
Depreciation and amortization	**259.7**	255.4	4.3
Property and revenue taxes	**55.5**	59.9	(4.4)
Utility margin (non-GAAP)	**$ 1,175.6**	$ 1,225.7	$ (50.1)

(1) Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) at the Illinois segment decreased $56.4 million during 2025, compared with 2024, and utility margin (non-GAAP) decreased $50.1 million during 2025, compared with 2024. Both measures were driven by a $75.0 million decrease in revenues due to PGL and NSG agreeing on the terms of a proposed settlement with the Illinois Attorney General that would resolve all open proceedings related to the QIP and UEA riders. See Note 26, Regulatory Environment, for more information.

This decrease in gross margin (GAAP) and utility margin (non-GAAP) was partially offset by:

- A $14.5 million increase in revenues associated with certain riders that are offset in other operation and maintenance and therefore do not have a significant impact on net income.

- A $12.9 million increase in revenues driven by a disallowance recorded in 2024 related to an ICC order received in August 2024 related to PGL's 2016 Rider QIP reconciliation prudency review, which required refunds to ratepayers for amounts previously collected related to the disallowance of certain capital costs. See Note 26, Regulatory Environment, for more information.

- A $2.2 million increase in revenues related to the impact of the NSG rate order issued by the ICC, effective February 1, 2024.

Additionally, the larger decrease in gross margin (GAAP) as compared with the decrease in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $4.3 million increase in depreciation and amortization expense;

- A $3.7 million increase in costs associated with maintenance at the Manlove Gas Storage Field; and

- A partially offsetting $4.4 million decrease in property and revenue taxes.

Other Operating Expenses (includes other operation and maintenance, impairments, depreciation and amortization, and property and revenue taxes)

Other operating expenses at the Illinois segment increased $124.0 million, net of the $14.5 million impact of the riders referenced in the table above, during 2025, compared with 2024. The significant factors impacting the increase in other operating expenses were:

- A $130.0 million impairment related to PGL and NSG agreeing on the terms of a proposed settlement with the Illinois Attorney General that would resolve all open proceedings related to the QIP and UEA riders. See Note 26, Regulatory Environment, for more information.

- A $7.4 million increase in expense primarily associated with the favorable settlement of a legal claim during 2024.

- A $4.3 million increase in depreciation and amortization expense, driven by assets being placed into service as we continue to execute on our capital plan.

- A $3.7 million increase in costs associated with maintenance at the Manlove Gas Storage Field.

These increases in operating expenses were partially offset by:

- A $12.1 million impairment recorded in 2024 related to an ICC order received in August 2024 related to the 2016 annual prudency review of PGL's QIP rider, which included a disallowance of certain capital costs. See Note 26, Regulatory Environment, for more information.

- A $4.4 million decrease in property and revenue taxes, driven by the invested capital tax.

Interest Expense

Interest expense at the Illinois segment decreased $5.8 million during 2025, compared with 2024, due to lower average short-term debt balances, lower average short-term debt interest rates, and the impact of a series of PGL's first mortgage bonds maturing in November 2024.

Income Tax Expense

Income tax expense at the Illinois segment decreased $51.8 million during 2025, compared with 2024, driven by a decrease in pre-tax income.

Other States Segment Contribution to Net Income Attributed to Common Shareholders

The other states segment's contribution to net income attributed to common shareholders for the year ended December 31, 2025 was $60.8 million, representing a $6.3 million, or 11.6%, increase over the prior year. The increase was driven by higher margins related to positive impacts from MGU's rate increase that was effective January 1, 2025, MERC's rate increase that was effective March 1, 2024, and an increase in retail sales volumes. These increases in earnings were partially offset by higher operating expenses. See Note 26, Regulatory Environment, for more information on the MGU and MERC rate increases.

Since the majority of MERC and MGU customers use natural gas for heating, net income attributed to common shareholders is sensitive to weather and is generally higher during the winter months.

(in millions)	Year Ended December 31 2025	2024	B (W)
Operating revenues	**$ 527.5**	$ 449.8	$ 77.7
Operating expenses			
Cost of natural gas sold	**246.3**	198.6	(47.7)
Other operation and maintenance	**104.6**	93.9	(10.7)
Depreciation and amortization	**49.8**	47.0	(2.8)
Property and revenue taxes	**26.2**	21.0	(5.2)
Operating income	**100.6**	89.3	11.3
Other income, net	**0.4**	0.3	0.1
Interest expense	**19.2**	16.4	(2.8)
Income before income taxes	**81.8**	73.2	8.6
Income tax expense	**21.0**	18.7	(2.3)
Net income attributed to common shareholders	**$ 60.8**	$ 54.5	$ 6.3

The following table shows a breakdown of other operation and maintenance:

(in millions)	Year Ended December 31 2025	2024	B (W)
Operation and maintenance not included in line item below	**$ 81.9**	$ 76.8	$ (5.1)
Regulatory amortizations and other pass through expenses [1]	**22.7**	17.1	(5.6)
Total other operation and maintenance	**$ 104.6**	$ 93.9	$ (10.7)

[1] Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on net income.

The following tables provide information on delivered sales volumes by customer class and weather statistics:

Natural Gas Sales Volumes (*Therms - in millions)*	Year Ended December 31 2025	2024	B (W)
Customer Class			
Residential	**325.9**	285.2	40.7
Commercial and industrial	**209.2**	179.9	29.3
Total retail	**535.1**	465.1	70.0
Transportation	**759.3**	828.5	(69.2)
Total sales in therms	**1,294.4**	1,293.6	0.8

Weather *(Degree Days)* [1]	Year Ended December 31 2025	2024	B (W)
MERC			
Heating (7,888 Normal)	**7,714**	6,792	13.6 %
MGU			
Heating (6,095 Normal)	**6,126**	5,083	20.5 %

[1] Normal heating degree days for MERC and MGU are based on a 20-year moving average and 15-year moving average, respectively, of monthly temperature readings from National Oceanic and Atmospheric Administration weather stations throughout their respective service territories.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our other states segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See Non-GAAP Financial Measures above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

	Year Ended December 31		
(in millions)	2025	2024	B (W)
Operating revenues	**$ 527.5**	$ 449.8	$ 77.7
Operating expenses			
Cost of natural gas sold	**(246.3)**	(198.6)	(47.7)
Other operation and maintenance [1]	**(59.0)**	(55.4)	(3.6)
Depreciation and amortization	**(49.8)**	(47.0)	(2.8)
Property and revenue taxes	**(26.2)**	(21.0)	(5.2)
Gross margin (GAAP)	**146.2**	127.8	18.4
Other operation and maintenance [1]	**59.0**	55.4	3.6
Depreciation and amortization	**49.8**	47.0	2.8
Property and revenue taxes	**26.2**	21.0	5.2
Utility margin (non-GAAP)	**$ 281.2**	$ 251.2	$ 30.0

[1] Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) increased $18.4 million during 2025, compared to 2024, and utility margin (non-GAAP) increased $30.0 million during 2025, compared to 2024. Both measures were driven by:

- A $10.5 million increase related to MGU's rate increase that was effective January 1, 2025, and MERC's rate increase that was effective March 1, 2024.

- A $10.3 million increase related to higher sales volumes, driven by colder weather during 2025, compared to 2024. As measured by heating degree days, 2025 was 13.6% and 20.5% colder than 2024 at MERC and MGU, respectively.

- A $5.3 million increase related to MERC CIP revenue, which was offset in operation and maintenance expense. Rebates and programs are available to residential and commercial customers of MERC through the CIP, which is funded by rate payers using the Conservation Cost Recovery Charge and the Conservation Cost Recovery Adjustment funds that are collected on their monthly billing statements.

- A $3.3 million increase related to MGU's energy optimization program, which provides rebates, incentives, and energy efficiency education to customers.

Additionally, the lower increase in gross margin (GAAP) as compared to the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $5.2 million increase in property and revenue taxes;

- A $3.6 million increase in natural gas operations and customer service expense; and

- A $2.8 million increase in depreciation and amortization.

Other Operating Expenses (includes other operation and maintenance, depreciation and amortization, and property and revenue taxes)

Other operating expenses at the other states segment increased $18.7 million during 2025, compared with 2024. The significant factors impacting the increase in operating expenses were:

- A $5.3 million increase in operation and maintenance expense related to MERC's CIP program, which has an offsetting increase in margins.
- A $5.2 million increase in property and revenue taxes, driven by the year-over-year impact from a positive resolution of a use tax audit at MGU during 2024.
- A $3.6 million increase in natural gas operations and customer service expense, driven by higher metering costs and call center expense at MERC and MGU.
- A $2.8 million increase in depreciation and amortization related to continued capital investment.
- A $1.4 million increase in bad debt expense, primarily at MERC. MERC's bad debt expense was lower in 2024 due to reserve adjustments related to improved loss rates.

Interest Expense

Interest expense at the other states segment increased $2.8 million during 2025, compared with 2024, driven by the impact of MERC issuing long-term debt in April 2025 and MGU issuing long-term debt in October 2024 and April 2025. This increase was partially offset by lower average short-term debt interest rates.

Income Tax Expense

Income tax expense at the other states segment increased $2.3 million during 2025, compared with 2024, driven by an increase in pre-tax income.

Electric Transmission Segment Contribution to Net Income Attributed to Common Shareholders

	Year Ended December 31		
(in millions)	**2025**	**2024**	**B (W)**
Equity in earnings of transmission affiliates	**$ 215.8**	$ 207.5	$ 8.3
Interest expense	**19.3**	19.4	0.1
Income before income taxes	**196.5**	188.1	8.4
Income tax expense	**48.9**	47.1	(1.8)
Net income attributed to common shareholders	**$ 147.6**	$ 141.0	$ 6.6

Equity in Earnings of Transmission Affiliates

Equity in earnings of transmission affiliates increased $8.3 million during 2025, compared with 2024. This increase was primarily due to continued capital investment by ATC. A $3.6 million gain related to the sale of an investment at ATC Holdco in March 2025 also contributed to the increase. Partially offsetting these increases was a $20.1 million increase in equity earnings recognized in 2024 related to the impact of a FERC order issued in October 2024 that addressed complaints related to ATC's ROE. For information on this FERC order, see Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – American Transmission Company Allowed Return on Equity Complaints.

Income Tax Expense

Income tax expense at the electric transmission segment increased $1.8 million during 2025, compared with 2024, driven by an increase in pre-tax income.

Non-Utility Energy Infrastructure Segment Contribution to Net Income Attributed to Common Shareholders

	Year Ended December 31		
(in millions)	**2025**	**2024**	**B (W)**
Operating income	**$ 405.3**	$ 393.0	$ 12.3
Other income, net	**2.8**	1.0	1.8
Interest expense	**123.1**	99.7	(23.4)
Income before income taxes	**285.0**	294.3	(9.3)
Income tax benefit	**(122.9)**	(82.4)	40.5
Net loss attributed to noncontrolling interests	**3.2**	4.1	(0.9)
Net income attributed to common shareholders	**$ 411.1**	$ 380.8	$ 30.3

Operating Income

Operating income at the non-utility energy infrastructure segment increased $12.3 million during 2025, compared with 2024, driven by these items at WECI:

- A $26.4 million increase in operating income from new investments in several WECI renewable generation facilities made in late 2024 and early 2025.

- A $7.5 million positive impact due to lower transmission congestion that increased energy market prices.

These increases in operating income were partially offset by:

- A $15.9 million impairment loss recorded at Samson I, Delilah I, and Thunderhead related to storm damage.

- A $7.9 million increase in operation and maintenance expenses due primarily to a higher number of equipment repairs at our renewable generation facilities.

- A $2.2 million negative impact in 2025 related to the receipt of lower performance payments.

In addition to the above items at WECI, there was a $4.5 million positive impact from We Power due to continued capital investment.

Interest Expense

Interest expense at the non-utility energy infrastructure segment increased $23.4 million during 2025, compared with 2024, driven by the impact of WECI Energy Holding III issuing long-term debt in December 2024.

Income Tax Benefit

The income tax benefit at the non-utility energy infrastructure segment increased $40.5 million during 2025, compared with 2024. The increase was primarily due to an increase in PTCs that was related to the acquisition of additional renewable generation facilities in the fourth quarter of 2024 and the first quarter of 2025, and an IRS approved PTC rate increase, partially offset by lower production volumes.

Corporate and Other Segment Contribution to Net Income Attributed to Common Shareholders

	Year Ended December 31		
(in millions)	**2025**	**2024**	**B (W)**
Operating loss	**$ (11.5)**	$ (11.3)	$ (0.2)
Other income, net	**30.6**	54.4	(23.8)
Interest expense	**359.0**	310.0	(49.0)
Gain on debt extinguishment	**—**	(23.1)	(23.1)
Loss before income taxes	**(339.9)**	(243.8)	(96.1)
Income tax benefit	**(101.0)**	(79.5)	21.5
Net loss attributed to common shareholders	**$ (238.9)**	$ (164.3)	$ (74.6)

Other Income, Net

Other income, net at the corporate and other segment decreased $23.8 million during 2025, compared with 2024. The significant factors impacting the decrease in other income, net were:

- A $15.1 million decrease due to net losses of $12.8 million from our equity method investments in technology and energy-focused investment funds during 2025, compared with net earnings of $2.3 million during 2024.

- A $6.6 million decrease in interest income, driven by the year-over-year negative impact from a $3.5 million gain recorded in 2024 related to the redemption of a long-term intercompany note WECI issued to WEC Energy Group. This decrease in intercompany interest income was offset by lower intercompany interest expense at our non-utility energy infrastructure segment. Lower interest income on cash balances of $3.4 million also contributed to the decrease in interest income.

- A $3.6 million decrease due to lower net gains from the investments held in the Integrys rabbi trust. The gains from the investments held in the rabbi trust partially offset the changes in benefit costs related to deferred compensation, which are primarily included in other operation and maintenance expense in our utility segments. See Note 17, Fair Value Measurements, for more information on our investments held in the Integrys rabbi trust.

Interest Expense

Interest expense at the corporate and other segment increased $49.0 million during 2025, compared with 2024, primarily due to the impact of long-term debt issuances in May and December 2024, as well as June and November 2025. This increase was partially offset by long-term debt maturities and redemptions. See Note 14, Long-Term Debt, for more information. Also partially offsetting the increase was lower than average short-term debt interest rates.

Gain on Debt Extinguishments

There was no gain on debt extinguishments during 2025, as we did not have an early settlement on any debt obligations. In 2024, the gain on debt extinguishments was driven by the early retirement of a portion of both our 5.60% Senior Notes due September 12, 2026 and our 1.80% Senior Notes due October 15, 2030. Also, during 2024, we recorded gains on redemptions and repurchases of our 2007 Junior Notes.

Income Tax Benefit

The income tax benefit at the corporate and other segment increased $21.5 million during 2025, compared with 2024, driven by an increase in pre-tax loss.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We expect to maintain adequate liquidity to meet our cash requirements for operation of our businesses and implementation of our corporate strategy through internal generation of cash from operations and access to the capital markets.

The following discussion and analysis of our Liquidity and Capital Resources includes comparisons of our cash flows for the year ended December 31, 2025 with the year ended December 31, 2024. For a similar discussion that compares our cash flows for the year ended December 31, 2024 with the year ended December 31, 2023, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources in Part II of our 2024 Annual Report on Form 10-K, which was filed with the SEC on February 21, 2025.

Cash Flows

The following table summarizes our cash flows during the years ended December 31:

(in millions)	2025	2024	Change in 2025 Over 2024
Cash provided by (used in):			
Operating activities	**$ 3,379.4**	$ 3,211.8	$ 167.6
Investing activities	**(4,874.7)**	(3,802.5)	(1,072.2)
Financing activities	**1,524.0**	467.7	1,056.3

Operating Activities

Net cash provided by operating activities increased $167.6 million during 2025, compared with 2024, driven by:

- A $338.7 million increase in cash from higher overall collections from customers during 2025, compared with 2024. This increase was driven by the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, and higher sales volumes from favorable weather during 2025, compared with 2024.

- A $42.3 million increase in cash from lower payments for environmental remediation related to work completed on former manufactured gas plant sites during 2025, compared with 2024.

- A $36.5 million increase in cash from higher distributions from ATC during 2025, compared with 2024. See Note 21, Investment in Transmission Affiliates, for more information.

These increases in net cash provided by operating activities were partially offset by:

- A $163.6 million decrease in cash from higher payments for operating and maintenance expenses. During 2025, our payments were higher due to increased transmission costs, operating and maintenance costs related to our plants, and electric and natural gas distribution costs.

- A $72.8 million decrease in cash from higher payments for interest driven by higher amounts of outstanding long-term debt in 2025, compared with 2024, partially offset by lower payments for interest due to a decrease in short-term interest rates during 2025, compared with 2024.

- A $20.1 million decrease in cash driven by higher amounts of collateral paid to counterparties during 2025, compared with 2024, partially offset by lower realized losses on derivative instruments recognized during 2025, compared with 2024.

Investing Activities

Net cash used in investing activities increased $1,072.2 million during 2025, compared with 2024, driven by:

- A $1,617.0 million increase in cash paid for capital expenditures during 2025, compared with 2024, which is discussed in more detail below.
- The acquisition of a 90% ownership interest in Hardin III in February 2025 for $406.1 million, net of cash acquired of $0.2 million.
- A $96.9 million increase in capital contributions paid to transmission affiliates during 2025, compared with 2024. See Note 21, Investment in Transmission Affiliates, for more information.

These increases in net cash used in investing activities were partially offset by:

- The acquisition of a 90% ownership interest in Delilah I in December 2024 for $462.5 million, net of cash acquired of $0.6 million.
- The acquisition of a 90% ownership interest in Maple Flats in November 2024 for $431.2 million, net of cash acquired of $0.5 million.
- The acquisition of an additional 13.7% ownership interest in West Riverside in May 2024 for $97.9 million.
- A $31.7 million increase in cash received from ATC during 2025, compared with 2024, for the reimbursement of transmission infrastructure upgrades. See Note 21, Investment in Transmission Affiliates, for more information.

For more information on our acquisitions, see Note 2, Acquisitions.

Capital Expenditures

Capital expenditures by segment for the years ended December 31 were as follows:

Reportable Segment *(in millions)*	**2025**	**2024**	**Change in 2025 Over 2024**
Wisconsin	**$ 3,860.1**	$ 2,247.1	$ 1,613.0
Illinois	**306.1**	343.0	(36.9)
Other states	**112.5**	118.3	(5.8)
Non-utility energy infrastructure	**98.6**	52.1	46.5
Corporate and other	**20.8**	20.6	0.2
Total capital expenditures	**$ 4,398.1**	$ 2,781.1	$ 1,617.0

The increase in cash paid for capital expenditures at the Wisconsin segment during 2025, compared with 2024, was driven by an increase in capital expenditures for the following: renewable energy projects at WE, WPS, and UMERC; CTs and an LNG facility at OCPP; WE's and WPS's electric distribution systems; and software to enhance productivity, collaboration, and overall efficiency across the company. These increases in capital expenditures were partially offset by decreased payments for construction of WPS's service center completed in October 2024 and WG's LNG facility completed in February 2024.

The decrease in cash paid for capital expenditures at the Illinois segment during 2025, compared with 2024, was driven by lower payments related to PGL's upgrade of its natural gas delivery system. For more information on the factors contributing to this decrease, see Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Illinois Proceedings. This decrease in capital expenditures was partially offset by increased capital expenditures at Manlove Gas Storage Field.

The increase in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2025, compared with 2024, was driven by an increase in capital expenditures related to new generator units at ERGS and PWGS.

See Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects below for more information.

Financing Activities

Net cash provided by financing activities increased $1,056.3 million during 2025, compared with 2024, driven by:

- A $1,709.7 million increase in cash due to $806.9 million of net borrowings of commercial paper during 2025, compared with $902.8 million of net repayments of commercial paper during 2024.

- A $598.5 million increase in cash due to higher issuances of common stock during 2025, compared with 2024. See Note 11, Common Equity, for more information.

- A $409.1 million increase in cash due to lower retirements of long-term debt during 2025, compared with 2024.

- The purchase of an additional 10% ownership interest in Samson I in January 2024 for $28.1 million. See Note 2, Acquisitions, for more information.

- A $15.4 million increase in cash related to a higher number of stock options exercised during 2025, compared with 2024.

These increases in net cash provided by financing activities were partially offset by:

- A $1,616.4 million decrease in cash due to lower issuances of long-term debt during 2025, compared with 2024.

- A $91.6 million decrease in cash due to higher dividends paid on our common stock during 2025, compared with 2024. In January 2025, our Board of Directors increased our quarterly dividend by $0.0575 per share (6.9%) effective with the March 2025 dividend payment.

Significant Financing Activities

For more information on our financing activities, see Note 11, Common Equity, Note 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt.

Cash Requirements

We require funds to support and grow our businesses. Our significant cash requirements primarily consist of capital and investment expenditures, payments to retire and pay interest on long-term debt, the payment of common stock dividends to our shareholders, and the funding of our ongoing operations. Our significant cash requirements are discussed in further detail below.

Significant Capital Projects

We have several capital projects and acquisitions that will require significant capital expenditures over the next three years and beyond. All projected capital requirements are subject to periodic review and may vary significantly from estimates, depending on a number of factors. These factors include environmental and regulatory requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, economic trends, supply chain disruptions, inflation, and interest rates. Our estimated capital expenditures and acquisitions for the next three years are reflected below. These amounts include anticipated expenditures for environmental compliance and certain remediation issues. For a discussion of certain environmental matters affecting us, see Note 24, Commitments and Contingencies.

(in millions)	2026	2027	2028
Wisconsin	$ 4,223.0	$ 5,952.5	$ 5,949.7
Illinois	566.6	738.4	744.0
Other states	115.0	110.5	125.5
Non-utility energy infrastructure	98.2	132.5	125.0
Corporate and other	15.3	15.6	21.4
Total	$ 5,018.1	$ 6,949.5	$ 6,965.6

We are committed to investing in solar, wind, battery storage, and natural gas-fired generation. In addition, our utilities continue to upgrade their electric and natural gas distribution systems to enhance reliability. Below are the anticipated amounts for the next three years for generation, LNG, and distribution projects that are proposed or currently underway.

(in millions)	2026	2027	2028
Generation:			
Solar	$ 734.3	$ 1,693.6	$ 1,713.1
Wind	160.9	311.7	654.3
Battery	258.4	413.1	253.5
Thermal	945.7	1,582.7	1,424.5
Other	481.8	309.0	365.8
LNG	178.0	82.0	112.0
Distribution:			
Electric distribution	972.2	946.4	973.3
Gas distribution	1,286.8	1,611.0	1,469.1
Total	$ 5,018.1	$ 6,949.5	$ 6,965.6

The DOC set duties on solar panels and cells imported from four southeast Asian countries and is investigating additional AD/CVD allegations relating to Chinese-owned manufacturers in Laos and Indonesia, as well as India-headquartered companies. See Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – United States Department of Commerce Complaints and Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Uyghur Forced Labor Prevention Act for information on the duties set by the DOC and its current investigation, as well as CBP actions, respectively. The expected in-service dates and costs identified above already reflect some of these impacts.

See Factors Affecting Results, Liquidity, and Capital Resources — Regulatory, Legislative, and Legal Matters — Renewable Energy Legislation for potential impacts to our capital projects as a result of the OBBBA.

In accordance with its November 2023 PGL rate order, the ICC initiated a proceeding in January 2024 to determine the optimal method and prudent investment level for replacing aging natural gas infrastructure. In February 2025, the ICC issued an order setting expectations for PGL's prospective retirement of its aging natural gas infrastructure. The ICC directed us to focus on retiring all cast and ductile iron pipe that has a diameter of less than 36 inches by January 1, 2035. PGL is working on retiring this cast and ductile iron pipe through its PRP. Annual investment for pipe replacement is expected to ramp up to approximately $500 million in 2028. For information on regulatory proceedings related to this matter, see Note 26, Regulatory Environment, and Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Illinois Proceedings.

We expect to provide total capital contributions to ATC (not included in the above table) of approximately $645 million from 2026 through 2028. We do not expect to make any contributions to ATC Holdco during that period. WEC's portion of the investment in MISO Tranche 1 and Tranche 2.1 is estimated to be approximately $700 million and $400 million, respectively, between 2026 and 2030, a portion of which will be funded by ATC's cash from operations. Tranche 1 is part of MISO's Long Range Transmission Planning initiative to upgrade the grid so that it can reliably accommodate for the shift in generation to lower-carbon resources. Tranche 2.1 is the second phase of long range transmission planning and builds on the foundation of Tranche 1.

Long-Term Debt

A significant amount of cash is required to retire and pay interest on our long-term debt obligations. See Note 14, Long-Term Debt, for more information on our outstanding long-term debt, including a schedule of our long-term debt maturities. The following table summarizes our required interest payments on long-term debt as of December 31, 2025:

	Interest Payments Due by Period				
(in millions)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Interest payments due on long-term debt	$ 8,972.8	$ 819.3	$ 1,430.9	$ 1,010.1	$ 5,712.5

Common Stock Dividends

On January 22, 2026, our Board of Directors increased our quarterly dividend to $0.9525 per share effective with the first quarter of 2026 dividend payment, an increase of 6.7%. This equates to an annual dividend of $3.81 per share.

We have been paying consecutive quarterly dividends dating back to 1942 and expect to continue paying quarterly cash dividends in the future. Any payment of future dividends is subject to approval by our Board of Directors and is dependent upon future earnings, capital requirements, and financial and other business conditions. In addition, our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future. See Note 11, Common Equity, for more information related to these restrictions and our other common stock matters.

Other Significant Cash Requirements

Our utility and non-utility operations have purchase obligations under various contracts for the procurement of fuel, power, and gas supply, as well as the related storage and transportation. These costs are a significant component of funding our ongoing operations. See Note 24, Commitments and Contingencies, for more information, including our minimum future commitments related to these purchase obligations.

In addition to our energy-related purchase obligations, we have commitments for other costs incurred in the normal course of business, including costs related to information technology services, meter reading services, maintenance and other service agreements for certain generating facilities, and various engineering agreements. Our estimated future cash requirements related to these purchase obligations, excluding energy-related obligations, are reflected below.

	Payments Due by Period				
(in millions)	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Purchase orders	$ 580.5	$ 278.0	$ 198.4	$ 63.5	$ 40.6

We have various finance and operating lease obligations. Our finance lease obligations primarily relate to land leases for our renewable generation projects. Our operating lease obligations are for office space and land. See Note 15, Leases, for more information, including an analysis of our minimum lease payments due in future years.

We make contributions to our pension and OPEB plans based upon various factors affecting us, including our liquidity position and tax law changes. See Note 20, Employee Benefits, for our expected contributions in 2026 and our expected pension and OPEB payments for the next 10 years. We expect the majority of these future pension and OPEB payments to be paid from our outside trusts. See Sources of Cash–Investments in Outside Trusts below for more information.

In addition to the above, our balance sheet at December 31, 2025 included various other liabilities that, due to the nature of the liabilities, the amount and timing of future payments cannot be determined with certainty. These liabilities include AROs, liabilities for the remediation of manufactured gas plant sites, and liabilities related to the accounting treatment for uncertainty in income taxes. For additional information on these liabilities, see Note 9, Asset Retirement Obligations, Note 16, Income Taxes, and Note 24, Commitments and Contingencies, respectively.

Off-Balance Sheet Arrangements

We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit that support construction projects, commodity contracts, and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources. See Note 13, Short-Term Debt and Lines of Credit, Note 19, Guarantees, and Note 23, Variable Interest Entities, for more information.

Sources of Cash

Liquidity

We anticipate meeting our short-term and long-term cash requirements to operate our businesses and implement our corporate strategy through internal generation of cash from operations and access to the capital markets, and common equity. Accessing the capital markets allows us to obtain external short-term borrowings, including commercial paper and term loans, and issue intermediate or long-term debt securities, as well as other types of securities. We also issue common equity through a combination of our employee benefit plans and stock purchase and dividend reinvestment plan, as well as through an at-the-market program. Cash generated from operations is primarily driven by sales of electricity and natural gas to our utility customers, reduced by costs of operations. Our access to the capital markets is critical to our overall strategic plan and allows us to supplement cash flows from operations with external borrowings to manage seasonal variations, working capital needs, commodity price fluctuations, unplanned expenses, and unanticipated events. Subject to market conditions and other factors, we may repurchase our debt securities through open market purchases, privately negotiated transactions and/or other types of transactions.

In January and February 2024, pursuant to a tender offer, we purchased $122.1 million aggregate principal amount of the $500.0 million outstanding of our 2007 Junior Notes for $115.2 million with proceeds from issuing commercial paper. We recorded a $6.4 million gain related to the early settlement. Additionally, in May 2024, we repurchased $19.0 million aggregate principal amount of the $377.9 million outstanding of our 2007 Junior Notes for $18.7 million, plus accrued interest, with proceeds received from issuing commercial paper. We recorded a $0.2 million gain related to the early settlement. In December 2024, we redeemed the remaining $358.9 million outstanding principal at par, plus accrued interest, of our 2007 Junior Notes with the proceeds we received from the issuance of our 2024A Junior Notes and 2024B Junior Notes.

In December 2024, pursuant to a tender offer, we repurchased $250.0 million aggregate principal amount of the $600.0 million outstanding of our 5.60% Senior Notes due September 12, 2026 and repurchased $150.0 million aggregate principal amount of the $450.0 million outstanding of our 1.80% Senior Notes due October 15, 2030, for $380.9 million, plus accrued interest, with proceeds received from issuing commercial paper. As a result of the repurchase, we recorded a $16.5 million gain on debt extinguishment.

WEC Energy Group, WE, WPS, WG, and PGL maintain bank back-up credit facilities, which provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes. We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations.

The amount, type, and timing of any financings in 2026, as well as in subsequent years, will be contingent on investment opportunities and our cash requirements and will depend upon prevailing market conditions, regulatory approvals for certain subsidiaries, and other factors. Our regulated utilities plan to maintain capital structures consistent with those approved by their respective regulators. For more information on our utilities approved capital structures, see Item 1. Business – E. Regulation.

The issuance of securities by our utility companies is subject to the approval of the applicable state commissions or FERC. Additionally, with respect to the public offering of securities, we, WE, and WPS file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are closely monitored and appropriate filings are made to ensure flexibility in the capital markets.

At December 31, 2025, our current liabilities exceeded our current assets by $2,308.7 million. We do not expect this to have an impact on our liquidity as we currently believe that our cash and cash equivalents, our available capacity under existing revolving credit facilities, cash generated from ongoing operations, and access to the capital markets are adequate to meet our short-term and long-term cash requirements.

See Note 11, Common Equity, Note 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt, for more information about our common stock activity, commercial paper, credit facilities, and debt securities.

Investments in Outside Trusts

We maintain investments in outside trusts to fund the obligation to provide pension and certain OPEB benefits to current and future retirees. As of December 31, 2025, these trusts had investments of approximately $3.6 billion, consisting of fixed income and equity securities, that are subject to the volatility of the stock market and interest rates. The performance of existing plan assets, long-term discount rates, changes in assumptions, and other factors could affect our future contributions to the plans, our financial position if our accumulated benefit obligation exceeds the fair value of the plan assets, and future results of operations related to changes in pension and OPEB expense and the assumed rate of return. For additional information, see Note 20, Employee Benefits.

Capitalization Structure

The following table shows our capitalization structure as of December 31, 2025 and 2024, as well as an adjusted capitalization structure that we believe is consistent with how a majority of the rating agencies currently view our Junior Notes:

	2025		2024	
(in millions)	**Actual**	**Adjusted** [(1)]	**Actual**	**Adjusted** [(2)]
Common shareholders' equity	**$ 13,613.6**	**$ 14,288.6**	$ 12,395.0	$ 12,770.0
Preferred stock of subsidiary	**30.4**	**30.4**	30.4	30.4
Long-term debt (including current portion)	**20,017.5**	**19,342.5**	18,907.1	18,532.1
Short-term debt	**1,924.7**	**1,924.7**	1,116.6	1,116.6
Total capitalization	**$ 35,586.2**	**$ 35,586.2**	$ 32,449.1	$ 32,449.1
Total debt	**$ 21,942.2**	**$ 21,267.2**	$ 20,023.7	$ 19,648.7
Ratio of debt to total capitalization	**61.7 %**	**59.8 %**	61.7 %	60.6 %

(1) Included in long-term debt on our Consolidated Balance Sheets as of December 31, 2025, was $600.0 million principal amount of WEC Energy Group's 2025 Junior Notes due 2056 and $750.0 million principal amount of WEC Energy Group's 2024 Junior Notes (2024A Junior Notes and 2024B Junior Notes, collectively) due 2055. The adjusted presentation at December 31, 2025 attributes $675.0 million of the Junior Notes to common equity and $675.0 million to long-term debt, similar to how the majority of rating agencies treat them.

(2) Included in long-term debt on our Consolidated Balance Sheets as of December 31, 2024, was $750.0 million principal amount of WEC Energy Group's 2024 Junior Notes (2024A Junior Notes and 2024B Junior Notes, collectively) due 2055. The adjusted presentation at December 31, 2024 attributes $375.0 million of the Junior Notes to common equity and $375.0 million to long-term debt, similar to how the majority of rating agencies treat them.

The adjusted presentation of our consolidated capitalization structure is included as a complement to our capitalization structure presented in accordance with GAAP. Management evaluates and manages our capitalization structure, including our total debt to total capitalization ratio, using the GAAP calculation as adjusted to reflect the treatment of the 2025 Junior Notes and 2024 Junior Notes by the majority of rating agencies. Therefore, we believe the non-GAAP adjusted presentation reflecting this treatment is useful and relevant to investors in understanding how management and the rating agencies evaluate our capitalization structure.

Debt Covenants

Certain of our short-term and long-term debt agreements contain financial covenants that we must satisfy, including debt to capitalization ratios and debt service coverage ratios. At December 31, 2025, we were in compliance with all such covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 11, Common Equity, Note 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt, for more information.

Credit Rating Risk

Cash collateral postings and prepayments made with external parties, including postings related to exchange-traded contracts, and cash collateral posted by external parties were immaterial as of December 31, 2025. From time to time, we may enter into commodity contracts that could require collateral or a termination payment in the event of a credit rating change to below BBB- at S&P Global Ratings, a division of S&P Global Inc., and/or Baa3 at Moody's Investors Service, Inc. If WE had a sub-investment grade credit rating at December 31, 2025, it could have been required to post $106 million of additional collateral or other assurances pursuant to the terms of a PPA. We also have other commodity contracts that, in the event of a credit rating downgrade, could result in a reduction of our unsecured credit granted by counterparties.

In addition, access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

In March 2025, Moody's changed the rating outlook for PGL to stable from negative as a result of the ICC's February 2025 order setting expectations for PGL's retirement of aging natural gas infrastructure. Moody's affirmed PGL's ratings, including its Aa3 senior secured rating and its P-1 short term rating for commercial paper. See Note 26, Regulatory Environment, for more information on the outcome of the rate order.

In November 2025, Moody's changed the rating outlook for WPS to negative and WG to positive, both from stable. The negative outlook of WPS reflects the change in its financial ratios during 2025 along with the growing leverage associated with WPS's investments. Moody's affirmed WPS's ratings, including its A2 Issuer and senior unsecured ratings and Prime-1 commercial paper rating. The positive outlook for WG is a result of strong financial ratios that Moody's expects to be sustained over the next 12-18 months. Moody's also affirmed WG's ratings including its A3 senior unsecured rating and Prime-2 commercial paper rating.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

Competitive Markets

Electric Utility Industry

The FERC supports large RTOs, which directly impacts the structure of the wholesale electric market. Due to the FERC's support of RTOs, MISO uses the MISO Energy Markets to carry out its operations, including the use of LMPs to value electric transmission congestion and losses. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us.

Wisconsin

Electric utility revenues in Wisconsin are regulated by the PSCW. The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date, and it is uncertain when, if at all, retail choice might be implemented in Wisconsin.

Michigan

Michigan has adopted a limited retail choice program. Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. As a result, some of our small retail customers have switched to an alternative electric supplier. At December 31, 2025, Michigan law limited customer choice to 10% of an electric utility's Michigan retail load. Our iron ore mine customer, Tilden, is exempt from this 10% cap based on current law, but Tilden is required under a long-term agreement to purchase electric power from UMERC through March 2039. In addition, certain load increases by facilities already using an alternative electric supplier can still be serviced by their alternative electric supplier, when various conditions exist, even if the cap has already been met. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

Natural Gas Utility Industry

We offer natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Since these transportation customers continue to use our distribution systems to transport natural gas to their facilities, we earn distribution revenues from them. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is substantially offset by an equal reduction to natural gas costs.

Wisconsin

Our Wisconsin utilities offer both natural gas transportation service and interruptible natural gas sales to enable customers to better manage their energy costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Due to the PSCW's previous proceedings on natural gas industry regulation in a competitive environment, the PSCW currently provides all Wisconsin customer classes with competitive markets the option to choose a third-party natural gas supplier. All of our Wisconsin non-residential customer classes have competitive market choices and, therefore, can purchase natural gas directly from either a third-party supplier or their local natural gas utility. Since third-party suppliers can be used in Wisconsin, the PSCW has also adopted standards for transactions between a utility and its natural gas marketing affiliates.

We are currently unable to predict the impact, if any, of potential future industry restructuring on our results of operations or financial position.

Illinois

Absent extraordinary circumstances, potential competitors are not allowed to construct competing natural gas distribution systems in the service territories for PGL and NSG. A charter from the State of Illinois gives PGL the right to provide natural gas distribution service in the City of Chicago as a public utility. Further, the "first in the field" and public interest standards limit the ability of potential competitors to operate in an existing utility service territory. In addition, we believe it would be impractical to construct competing duplicate distribution facilities due to the high cost of installation.

Since 2002, PGL and NSG have, under ICC-approved tariffs, provided their customers with the option to choose a third-party natural gas supplier. There are no state laws requiring PGL and NSG to make this choice option available to customers, but since this option is currently provided to our Illinois customers under tariff, ICC approval would be needed to withdraw those tariffs.

An interstate pipeline may seek to provide transportation service directly to our Illinois end users, which would bypass our natural gas transportation service. However, PGL and NSG have anti-bypass tariffs approved by the ICC, which allow them to negotiate rates with customers that are potential bypass candidates to help ensure that such customers continue to use utility transportation service.

Minnesota

Natural gas utilities in the state of Minnesota do not have exclusive franchise service territories and, as a matter of law and policy, natural gas utilities may compete for new customers. However, natural gas utilities have customarily avoided competing for existing customers of other utilities, as there would be duplicative utility facilities and/or increased costs to customers. If this approach were to change, it could lead to a greater level of competition amongst utilities to obtain customers and potentially adversely impact our results of operations.

MERC offers both natural gas transportation service and interruptible natural gas sales to enable customers to better manage their energy costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change. MERC has provided its commercial and industrial customers with the option to choose a third-party natural gas supplier since 2006. We are not required by the MPUC or state law to make this choice option available to customers, but since this option is currently provided to our Minnesota commercial and industrial customers, we would need MPUC approval to eliminate it.

Michigan

The option to choose a third-party natural gas supplier has been provided to UMERC’s natural gas customers (formerly WPS’s Michigan natural gas customers) since the late 1990s and MGU's customers since 2005. We are not required by the MPSC or state law to make this choice option available to customers, but since this option is currently provided to our Michigan customers, we would need MPSC approval to eliminate it.

Regulatory, Legislative, and Legal Matters

Regulatory Recovery

Our utilities account for their regulated operations in accordance with accounting guidance under the Regulated Operations Topic of the FASB ASC. Our rates are determined by various regulatory commissions. See Item 1. Business – E. Regulation for more information on these commissions.

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense if the regulated entity believes the recovery of those costs is probable. We record regulatory assets pursuant to generic and/or specific orders issued by our regulators. Recovery of the deferred costs in future rates is subject to the review and approval by those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of the deferred costs, including those referenced below, is not approved by our regulators, the costs would be charged to income in the current period. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. See Note 6, Regulatory Assets and Liabilities, for more information on our regulatory assets and liabilities. See Note 26, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

Illinois Riders

Uncollectible Expense Adjustment Rider

The rates of PGL and NSG include a UEA rider for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The UEA rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency by the ICC. In May 2023, the ICC issued a written order on PGL's and NSG's 2018 UEA rider reconciliation. The order required a $15.4 million and $0.7 million refund to customers at PGL and NSG, respectively. These amounts were refunded over a period of nine months, which began on September 1, 2023. Upon appeal by PGL and NSG, the Illinois Appellate Court affirmed the ICC order and the related disallowance. The Illinois Supreme Court denied a subsequent petition for review and reversal of the order in March 2025.

As of December 31, 2025, there can be no assurance that all costs incurred under the UEA rider during the open reconciliation years will be deemed recoverable by the ICC. Future disallowances by the ICC could be material. The combined annual costs of PGL and NSG included in the rider, which reflect uncollectible write-offs in excess of what is recovered in base rates, have ranged from $10 million to $40 million. However, see Uncollectible Expense Adjustment and Qualifying Infrastructure Plant Riders Settlement below for information on a proposed settlement that would resolve all open proceedings.

Qualifying Infrastructure Plant Rider

In January 2014, the ICC approved PGL's use of the QIP rider as a recovery mechanism for costs incurred related to investments in QIP. This rider, which was in effect until December 1, 2023, continues to be subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In August 2024, the ICC issued a final order on PGL's 2016 annual reconciliation, which included a disallowance of $14.8 million of certain capital costs. PGL recorded a pre-tax charge to income of $25.3 million during the third quarter of 2024 related to the disallowance and the previously recognized return on and of these investments. The charge was recorded on the income statement as a $12.9 million reduction in revenues for the amounts previously collected from customers, a $12.1 million increase to operating expenses for the impairment of PGL's property, plant, and equipment, and a $0.3 million increase to interest expense related to the amounts due to customers. In October 2024, PGL filed a petition with the Illinois Appellate Court for review of the ICC's August 2024 order; however, in January 2026, PGL filed an unopposed motion to stay the appeal, which was granted by the court.

PGL's QIP reconciliations from 2017 through 2023 are still pending. Future disallowances by the ICC could be material. The aggregate capital costs included in the rider during the open reconciliation years, along with any previously recognized return on these investments, totaled approximately $3.0 billion as of December 31, 2025. However, see Uncollectible Expense Adjustment and Qualifying Infrastructure Plant Riders Settlement below for information on a proposed settlement that would resolve all open proceedings.

Uncollectible Expense Adjustment and Qualifying Infrastructure Plant Riders Settlement

In February 2026, PGL and NSG agreed on the terms of a proposed settlement with the Illinois Attorney General that, if approved by the ICC, would resolve all open proceedings related to the UEA and QIP riders. PGL and NSG agreed to refund $49.0 million and $1.0 million, respectively, to customers as bill credits over a three year period between 2026 and 2028 to resolve the open UEA proceedings. In order to resolve the open QIP proceedings, PGL agreed to permanently remove $130.0 million of qualified infrastructure investment costs from rate base starting in 2027 and to refund $75.0 million to customers as bill credits over a three year period between 2026 and 2028. As a result of this agreement, we recorded a $205.0 million charge to income during the fourth quarter of 2025. The charge was recorded as a $130.0 million impairment to PGL's net property, plant, and equipment and a $75.0 million reduction to revenues. The total of the rate base reduction and the obligation to refund amounts to customers through bill credits recorded on our balance sheet at December 31, 2025 is $255.0 million. This includes the $205.0 million charge to income recorded during 2025 and a $50.0 million charge to income recorded in prior years. This proposed settlement is subject to ICC approval following a public review process.

Illinois Proceedings

In the PGL rate order issued by the ICC in November 2023, the ICC ordered PGL to pause spending on its projects to upgrade its natural gas delivery system until the ICC completed a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level. In accordance with the written order, the ICC initiated the proceeding in January 2024. In February 2025, the ICC issued an order setting expectations for PGL's prospective operations. The ICC directed us to focus on retiring all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. The ICC also indicated that failure to comply with this directive could subject us to civil penalties under Illinois statute. PGL is working to retire this cast and ductile iron pipe through its PRP. Costs incurred under the PRP will be evaluated for prudency by the ICC in future rate cases. In addition, the program will be overseen by a safety monitor hired by the ICC. PGL initiated a general rate case proceeding in January 2026, which we anticipate will provide further regulatory clarity before we significantly increase our spend associated with the PRP.

In March 2024, the ICC initiated a statewide "Future of Gas" proceeding. The goal of this proceeding is to explore the issues involved with decarbonization of the gas distribution system in Illinois and recommend any future ICC action or legislative changes needed. It includes the formal exploration and consideration of the role of natural gas in the future, including in the context of the state's environmental and energy policy goals. The proceeding includes a broad range of stakeholders, including Illinois utilities and other interested parties. The "Future of Gas" proceeding is expected to be completed by the end of 2026. At this time, we cannot predict the ultimate outcome of this proceeding or the resulting impact to our natural gas operations in Illinois. Future natural gas investment opportunities in Illinois could be negatively impacted depending upon the outcome.

See Note 26, Regulatory Environment, for more information regarding the 2026 rate case filing and November 2023 ICC rate order.

Chicago Decarbonization Efforts

The CABO was introduced at a meeting of the Chicago city council held in January 2024. If approved, this ordinance would set an indoor emissions standard that would require zero-to-low-emission energy systems in newly built commercial and residential buildings and major building additions in the city of Chicago. The proposed emission standards would effectively prohibit the use of natural gas in new buildings and homes and require electric heat and appliances. The CABO would not impact existing homes and businesses. In addition, certain buildings and equipment, such as hospitals, commercial kitchens, and back-up generators, would be exempt from the new emission limits.

In response to the CABO, a resolution was also introduced that would require the formation of a working group comprised of various subject matter experts to analyze the costs of converting buildings from natural gas to electricity, the costs for additional electric generation capacity needed for future building conversions, and the impact of shifting natural gas system costs from new construction to existing buildings if electrification measures are adopted. If the resolution is passed, this analysis would need to be completed prior to the adoption of any decarbonization initiatives, such as the CABO.

If approved by the city council, the CABO is expected to become effective one year after the approval date. PGL's future natural gas operations could be materially adversely impacted if the CABO is passed.

Uyghur Forced Labor Prevention Act

In June 2022, the CBP implemented the UFLPA, which establishes a rebuttable presumption that certain silica-based products wholly or partially manufactured in the Xinjiang Uyghur Autonomous Region of China, such as polysilicon included in the manufacturing of solar panels, are prohibited from entering the United States. While our suppliers have been able to provide the CBP sufficient documentation to meet the UFLPA compliance requirements, and we expect the same will be true for subsequent projects, we cannot currently predict what, if any, long-term impact the UFLPA will have on the overall supply of solar panels into the United States and whether we will experience any further impacts to the timing and cost of solar projects included in our long-term capital plan.

In 2025, the Department of Homeland Security announced the addition of more Chinese businesses to the UFLPA, including several solar supply chain providers. We are working to avoid doing business with these companies and remain in compliance with the UFLPA.

United States Department of Commerce Complaints

Starting in June 2024, the DOC began applying duties to certain imports of solar cells from Malaysia, Vietnam, Thailand and Cambodia, with the potential for enhanced duties in certain circumstances, based on final findings by both the DOC and the USITC in their AD/CVD investigations that Chinese manufacturers were shifting products to those four Southeast Asian countries to avoid tariffs required on products imported from China.

In April 2025, based upon investigation in response to a new petition, the DOC reached affirmative findings that some Chinese companies had moved their solar operations to avoid penalties imposed in the first investigation, increasing tariff rates, in some cases significantly. These increased rates became effective and enforceable in May 2025 upon the USITC's final affirmative determination. As a result of these duties, the cost and availability of solar panels in the U.S. has been impacted and the U.S. solar industry overall has experienced higher costs of materials as well as delays. Some of these impacts have already been reflected in the estimated cost and in-service dates for certain of our solar projects.

In August 2025, in response to another petition filed by a coalition of trade groups, the DOC and USITC initiated new AD/CVD investigations based on the coalition's claims that Chinese-owned manufacturers in Laos and Indonesia, as well as India-headquartered companies, are benefiting from illegal subsidies and selling solar products below cost in the US. Affirmative findings in these investigations could cause further strain on the solar panel industry. We are monitoring the status of these petitions.

Renewable Energy Legislation

Infrastructure Investment and Jobs Act

In November 2021, the Infrastructure Investment and Jobs Act was signed into law and provides for approximately $1.2 trillion of federal spending through 2026, including approximately $85 billion for investments in power, utilities, and renewables infrastructure across the United States. Funding from this Act supports the work we are doing to reduce GHG emissions and to strengthen and protect the energy grid. In January 2025, disbursement of funds was paused until agency heads can determine whether grants, loans, contracts, and other disbursements are consistent with the current administration's energy policy. In some cases, the pause has disrupted, and could continue to disrupt, funding, temporarily or permanently, for infrastructure projects already in progress, may cause project delays and cancellations, and may impact continuing payment obligations for downstream contractors and suppliers.

Inflation Reduction Act

In August 2022, the IRA was signed into law and provides for $258 billion in energy-related provisions over a 10-year period. The IRA has helped reduce our cost of investing in projects that support our commitment to reduce emissions and provide affordable, reliable, and clean energy for our communities. We and our customers have benefited from the IRA's provisions to extend tax benefits for renewable technologies, increase or restore higher rates for PTCs, claim PTCs for solar projects, expand qualified ITC facilities to include standalone energy storage, and allow companies to transfer tax credits generated from renewable projects.

Under the IRA transferability option, we entered into agreements in October 2024, April 2025, and September 2025 to sell the majority of the PTCs and ITCs we generated, or expect to generate, in 2025 and 2026, respectively, to third parties. In May 2025, we entered into an agreement to sell the majority of our remaining unsold PTCs we generated in 2024 to a third party. See Note 1(q), Income Taxes, for more information about the impact of these sales. The IRA also implements a 15% corporate alternative minimum tax and a 1% excise tax on stock repurchases. Although significant regulatory guidance is expected on the tax provisions in the IRA, we currently believe the provisions on alternative minimum tax and stock repurchases will not have a material impact on us.

One Big Beautiful Bill Act

In July 2025, the OBBBA was signed into law, enacting significant modifications to clean-energy tax credits previously provided under the IRA. The OBBBA provides companies the ability to earn solar and wind tax credits at current credit rates if construction of projects begins by July 4, 2026, and the projects are placed in-service within four years after beginning construction. However, wind and solar projects that begin construction more than one year after enactment of the OBBBA must be placed in service by December 31, 2027 to qualify for PTCs and ITCs. In addition, wind and solar projects that begin construction after December 31, 2025 must also satisfy prohibited foreign entity material assistance requirements. The incentives can also be denied for taxpayers that exceed certain thresholds of equity or debt held by specified foreign entities. The phase out of PTCs and ITCs does not apply to energy storage, hydroelectric facilities, nuclear, or any other zero emission technology. The OBBBA preserves the ability to transfer tax credits, with the exception of transfers to a prohibited foreign entity. In August 2025, the U.S. Treasury Department implemented new beginning-of-construction safe harbor rules that became effective in September 2025. The capital plan for 2026 through 2030 reflects the impacts of OBBBA, including the revised beginning-of-construction rules.

Return on Equity Incentive for Membership in a Transmission Organization

The FERC currently allows transmission utilities, including ATC, to increase their ROE by 50 basis points as an incentive for membership in a transmission organization, such as MISO. This incentive was established to stimulate infrastructure development and to support the evolving electric grid. However, a Notice of Proposed Rulemaking was issued by the FERC on April 15, 2021, proposing to limit the 50 basis point increase in ROE to only be available to transmission utilities initially joining a transmission organization for the first three years of membership. If this proposal becomes a final rule, ATC would be required to submit, within 30 days of the final rule's effective date, a compliance filing eliminating the 50 basis point incentive from its tariff. As a result, we estimate that this proposal, if adopted, would reduce our future after-tax equity earnings from ATC by approximately $9 million annually on a prospective basis. The transmission costs WE, WPS, and UMERC are required to pay ATC after the effective date would also be reduced by this proposal.

American Transmission Company Allowed Return on Equity Complaint

The ROE allowed by the FERC helps determine how much transmission owners, such as ATC, earn on their transmission assets as well as how much consumers pay for those assets. When a complaint was filed arguing the base ROE for MISO transmission owners, including ATC, was too high, the FERC started analyzing the base ROE for these transmission owners.

The base ROEs listed in the ROE complaint section below do not include the 50 basis point ROE incentive currently provided for membership in a transmission organization. See the Return on Equity Incentive for Membership in a Transmission Organization section above for more information on this incentive.

Return on Equity Complaint

In November 2013, a group of MISO industrial customers filed a complaint with the FERC asking that the FERC order a reduction to the base ROE used by MISO transmission owners, including ATC, from 12.2% to 9.15%. Due to this complaint, the FERC and the D.C. Circuit Court of Appeals issued the following orders and opinion. The refunds resulting from these orders and opinion are also described below.

- September 2016 FERC Order – On September 28, 2016, the FERC issued an order reducing the base ROE for MISO transmission owners to 10.32% for the period covered by this complaint, November 12, 2013 through February 11, 2015 and September 28, 2016 going forward.

- November 2019 FERC Order – On November 21, 2019, the FERC issued another order after directing MISO transmission owners and other stakeholders to provide briefs and comments on a proposed change to the methodology for calculating base ROE. In this order, the FERC expanded its base ROE methodology to include the capital-asset pricing model in addition to the discounted cash flow model to better reflect how investors make their investment decisions. The FERC also rejected the use of the risk premium model as part of its base ROE methodology in this order. The FERC's modified methodology further reduced the base ROE for all MISO transmission owners, including ATC, to 9.88% for the period covered by the complaint. In response to this FERC decision, requests for the FERC to rehear the November 2019 Order in its entirety were filed by various parties.

- May 2020 FERC Order – On May 21, 2020, the FERC issued an order that granted in part and denied in part the requests to rehear the November 2019 Order. In this May 2020 Order, the FERC made additional revisions to its base ROE methodology, including reinstating the use of the risk premium model. The additional revisions made by the FERC increased the base ROE for all MISO transmission owners, including ATC, from the 9.88% authorized in the November 2019 Order to 10.02% for the period covered by the complaint. Various parties then filed requests to rehear certain parts of the May 2020 Order with the FERC.

- November 2020 FERC Order – In response to the rehearing requests filed concerning certain parts of the May 2020 Order, the FERC issued an order in November 2020 that confirmed the ROE previously authorized in its May 2020 Order.

- Refunds for FERC Orders Issued Prior to October 2024 – Due to the base ROE changes resulting from the FERC orders issued prior to October 2024, ATC was required to provide refunds, with interest, for the 15-month refund period from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 through November 19, 2020. In January 2022, ATC completed providing WE, WPS, and UMERC with the net refunds related to the transmission costs they paid during these periods. The refunds were applied to WE's and WPS's PSCW-approved escrow accounting for transmission expense.

- August 2022 D.C. Circuit Court of Appeals Opinion – Since several petitions for review were filed with the D.C. Circuit Court of Appeals concerning this ROE complaint, the D.C. Circuit Court of Appeals issued an opinion on August 9, 2022, addressing these petitions. In its August 2022 Opinion, the D.C. Circuit Court of Appeals ruled the FERC failed to adequately explain why it reinstated the use of the risk premium model as part of its ROE methodology in its May 2020 Order after previously rejecting the model in its November 2019 Order. Due to this ruling, the D.C. Circuit Court of Appeals vacated the FERC’s previous orders and remanded the issue of determining an appropriate base ROE for MISO transmission owners back to the FERC for additional proceedings. As a result, ATC recorded a reserve for potential refunds based on a 9.88% base ROE.

- October 2024 FERC Order – In response to the August 2022 D.C. Circuit Court of Appeals Opinion, the FERC issued an order on October 17, 2024. The FERC’s October 2024 Order removed the risk premium model from the base ROE methodology and required MISO transmission owners, including ATC, to adopt a 9.98% base ROE for the period covered by the complaint.

- Refunds for FERC Order Issued in October 2024 – Prior to the October 2024 FERC order, the base ROE for MISO transmission owners was 10.02% based on the November 2020 FERC order. Since the October 2024 FERC order changed the base ROE to 9.98%, ATC will be providing additional refunds, with interest, for the 15-month refund period from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 through October 17, 2024. As a result, WE, WPS, and UMERC are receiving refunds from ATC related to the transmission costs they paid during these two refund periods. The refunds are being applied to WE’s and WPS’s PSCW-approved escrow accounting for transmission expense.

  Due to the change between the 9.88% base ROE originally reflected in ATC's reserve and the 9.98% base ROE authorized in the October 2024 FERC Order, ATC reduced its refund liability, which increased our pre-tax equity earnings by $20.1 million in 2024.

- March 2025 FERC Order – In response to rehearing requests filed concerning the October 2024 FERC Order, the FERC issued an order on March 25, 2025 that reaffirmed the October 2024 FERC Order in its entirety. Appeals related to the October 2024 FERC Order are still pending before the D.C. Circuit Court of Appeals.

Environmental Matters

See Note 24, Commitments and Contingencies, for a discussion of certain environmental matters affecting us, including rules and regulations relating to air quality, water quality, and land quality.

Market Risks and Other Significant Risks

We are exposed to market and other significant risks as a result of the nature of our businesses and the environments in which those businesses operate. These include, but are not limited to, the risks described below. In addition, there is continuing uncertainty over the impact of increasing tensions between the U.S. and other countries and new, protracted or escalating regional and international conflicts on the global economy, supply chains, and fuel prices.

Commodity Costs

In the normal course of providing energy, we are subject to market fluctuations in the costs of coal, natural gas, purchased power, and fuel oil used in the delivery of coal. We manage our fuel and natural gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of coal, natural gas, and fuel oil. In addition, we manage the risk of price volatility through natural gas and electric hedging programs.

Embedded within our utilities' rates are amounts to recover fuel, natural gas, and purchased power costs. Our utilities have recovery mechanisms in place that generally allow them to recover or refund all or a portion of the changes in prudently incurred fuel, natural gas, and purchased power costs from rate case-approved amounts. See Item 1. Business – E. Regulation for more information on these mechanisms.

Higher commodity costs can increase our working capital requirements, result in higher gross receipts taxes, and lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution. Higher commodity costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. See Note 5, Credit Losses, for more information on riders and other mechanisms that allow for cost recovery or refund of uncollectible expense.

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric utility margins are unfavorably sensitive to below normal temperatures during the summer cooling season and, to some extent, to above normal temperatures during the winter heating season. Our natural gas utility margins are unfavorably sensitive to above normal temperatures during the winter heating season. PGL, NSG, and MERC have decoupling mechanisms in place that help reduce the impacts of weather. Decoupling mechanisms differ by state and allow utilities to recover or refund certain differences between actual and authorized margins. A summary of actual weather information in our utilities' service territories, as measured by degree days, can be found in Results of Operations.

Our utility operations (primarily our electric utility operations) and the operations of WECI, can be negatively impacted by storms. High wind conditions, lightning, hail, and flooding from these storms can result in downed wires and poles, as well as damage to wind and solar generation facilities and other operating equipment. This can result in us incurring significant restoration costs at our utilities and at WECI, including lost revenue to customers. Our utilities' rates include a fixed amount for expected storm restoration costs. To the extent actual storm restoration costs are above what is included in these rates, earnings at our utility operations are negatively impacted and it becomes more difficult to achieve our authorized ROEs. Similarly, restoration costs and lost revenue from storms negatively impacts operations and earnings at our non-utility WECI renewable generation facilities.

Interest Rates

We are exposed to interest rate risk resulting from our short-term and long-term borrowings and projected near-term debt financing needs. We manage exposure to interest rate risk by limiting the amount of our variable rate obligations and continually monitoring the effects of market changes on interest rates. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at December 31, 2025 and 2024, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $19.2 million and $11.2 million in 2025 and 2024, respectively. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Marketable Securities Return

We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. The financial risks associated with investment returns are mitigated at our Wisconsin utilities through the requirement that WE, WPS, and WG implement escrow accounting treatment for pension and OPEB costs in 2023 through 2026, as required by the December 2022 and December 2024 rate orders issued by the PSCW. As a result, our Wisconsin utilities defer as a regulatory asset or liability, the difference between actual pension and OPEB costs and those included in rates until recovery or refund is authorized in a future rate proceeding. We also believe that the financial risks associated with investment returns would be partially mitigated at our other utilities through future rate actions by regulators.

The fair value of our trust fund assets and expected long-term returns were approximately:

(in millions)	As of December 31, 2025	Expected Return on Assets in 2026
Pension trust funds	$ **2,664.0**	6.61 %
OPEB trust funds	$ **904.5**	6.50 %

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations are intended to reduce risk, provide long-term financial stability for the plans, and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the funds.

Economic Conditions

We have electric and natural gas utility operations that serve customers in Wisconsin, Illinois, Minnesota, and Michigan. As such, we are exposed to market risks in the regional Midwest economy. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our products.

Changes to United States Trade Policy (Tariff Activity)

The U.S. continues to implement changes to its international trade policy including changes to tariffs, port fees and other policies relating to exports from and imports into the United States. In response to these changes, foreign governments also continue to adjust their trade policies, including the imposition of additional tariffs. There remains significant uncertainty as to the ultimate scope of the U.S. and foreign trade policies. Both the U.S. and foreign trade policy changes could increase the cost of materials or disrupt supply chains, which could impact our ability to repair or maintain our infrastructure; the timing, cost or completion of our infrastructure projects; and/or our ability to execute our capital plan. In addition, these changes, including any impact they may have to economic conditions, could lead to reduced energy demand by our customers. Consequently, these policy changes could have a material adverse effect on our business, results of operations and financial condition.

Inflation and Supply Chain Disruptions

We continue to monitor the impact of inflation and supply chain disruptions. We monitor the costs of medical plans, fuel, transmission access, construction costs, regulatory and environmental compliance costs, and other costs in order to minimize inflationary effects in future years, to the extent possible, through pricing strategies, productivity improvements, and cost reductions. We monitor the global supply chain, and related disruptions, in order to ensure we are able to procure the materials and other resources necessary to both maintain our energy services in a safe and reliable manner and to grow our infrastructure in accordance with our capital plan. For additional information concerning risks related to inflation and supply chain disruptions, see the four risk factors below.

- Item 1A. Risk Factors – Risks Related to the Operation of Our Business – Public health crises, including epidemics and pandemics, could adversely affect our business functions, financial condition, liquidity, and results of operations.

- Item 1A. Risk Factors – Risks Related to the Operation of Our Business – Our operations and corporate strategy may be adversely affected by supply chain disruptions, inflation, and tariffs.

- Item 1A. Risk Factors – Risks Related to the Operation of Our Business – We are actively involved with multiple significant capital projects, which are subject to a number of risks and uncertainties that could adversely affect project costs and completion of construction projects.

- Item 1A. Risk Factors – Risks Related to Economic and Market Volatility – The fluctuation in demand for certain commodities and their respective prices could negatively impact our operations.

For additional information concerning other risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report and Item 1A. Risk Factors.

Critical Accounting Policies and Estimates

The preparation of financial statements in compliance with GAAP requires the application of accounting policies, as well as the use of estimates, assumptions, and judgments that could have a material impact on our financial statements and related disclosures. Judgments regarding future events may include the likelihood of success of particular projects, legal and regulatory challenges, and anticipated recovery of costs. Actual results may differ significantly from estimated amounts based on varying assumptions.

Our significant accounting policies are described in Note 1, Summary of Significant Accounting Policies. The following is a list of accounting policies and estimates that require management's most difficult, subjective, or complex judgments and may change in subsequent periods.

Regulatory Accounting

Our utility operations follow the guidance under the Regulated Operations Topic of the FASB ASC (Topic 980). Our financial statements reflect the effects of the ratemaking principles followed by the jurisdictions regulating us. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by our regulators.

Future recovery of regulatory assets, including the timeliness of recovery and our ability to earn a reasonable return, is not assured and is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Once approved, the regulatory assets and liabilities are amortized into earnings over the rate recovery or refund period. If recovery or refund of costs is not approved or is no longer considered probable, these regulatory assets or liabilities are recognized in current period earnings. Management regularly assesses whether these regulatory assets and liabilities are probable of future recovery or refund by considering factors such as changes in the regulatory environment, earnings from our electric and natural gas utility operations, rate orders issued by our regulators, historical decisions by our regulators regarding regulatory assets and liabilities, and the status of any pending or potential deregulation legislation.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our utility operations no longer met the criteria for application. Our regulatory assets and liabilities would be written off to income as an unusual or infrequently occurring item in the period in which discontinuation occurred. See Note 6, Regulatory Assets and Liabilities, for more information on our regulatory assets and liabilities.

Goodwill

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2025. No impairments were recorded as a result of these tests. For all of our reporting units, the fair values calculated in step one of the test were greater than their carrying values. The fair values for the reporting units were calculated using a combination of the income approach and the market approach.

For the income approach, we used internal forecasts to project cash flows. Any forecast contains a degree of uncertainty, and changes in these cash flows could significantly increase or decrease the calculated fair value of a reporting unit. For our reporting units that are regulated, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair values of our reporting units to decrease.

Key assumptions used in the income approach include ROEs, the long-term growth rates used to determine terminal values at the end of the discrete forecast period, and the discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is driven by its current allowed ROE. The terminal growth rate is based primarily on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

For the market approach, we used a higher weighting for the guideline public company method than the guideline merged and acquired company method due to a low number of mergers and acquisitions in recent years. The guideline public company method uses financial metrics from similar publicly traded companies to determine fair value. The guideline merged and acquired company method calculates fair value by analyzing the actual prices paid for recent mergers and acquisitions in the industry. We applied multiples derived from these two methods to the appropriate operating metrics for our reporting units to determine fair value.

The underlying assumptions and estimates used in the impairment tests were made as of a point in time. Subsequent changes in these assumptions and estimates could change the results of the tests.

For all of our reporting units that carried a goodwill balance at July 1, 2025, the fair value exceeded its carrying value by over 50%. Based on these results, our reporting units are not at risk of failing step one of the goodwill impairment test.

See Note 10, Goodwill and Intangibles, for more information.

Long-Lived Assets

In accordance with ASC 980-360, Regulated Operations – Property, Plant, and Equipment, we periodically assess the recoverability of certain long-lived assets when events or changes in circumstances indicate that the carrying amount of those long-lived assets may not be recoverable. Examples of events or changes in circumstances include, but are not limited to, a significant decrease in the market price, a significant change in use, a regulatory decision related to recovery of assets from customers, adverse legal factors or a change in business climate, operating or cash flow losses, or an expectation that the asset might be sold or abandoned. See Note 1(k), Asset Impairment, for our policy on accounting for abandonments and recently completed plant subject to disallowance.

Performing an impairment evaluation involves a significant degree of estimation and judgment by management in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets, and developing the undiscounted future cash flows. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset. The fair value of the asset is assessed using various methods, including recent comparable third-party sales for our nonregulated operations, internally developed discounted cash flow analysis, expected recovery of regulated assets, and analysis from outside advisors.

See Note 7, Property, Plant, and Equipment, for more information on our generating units probable of being retired. See Note 6, Regulatory Assets and Liabilities, for information on our retired generating units.

Pension and Other Postretirement Employee Benefits

The costs of providing non-contributory defined pension benefits and OPEB, described in Note 20, Employee Benefits, are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension and OPEB costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Pension and OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, mortality and discount rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and OPEB costs.

Pension and OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. Changes in benefit costs are mitigated at our Wisconsin utilities through the requirement that WE, WPS, and WG implement escrow accounting treatment for pension and OPEB costs, as required by rate orders issued by the PSCW. See Note 26, Regulatory Environment, for more information on rates at our Wisconsin utilities. We believe that changes to benefit costs at our other utilities would be recovered or refunded through the ratemaking process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost (including amounts capitalized to our balance sheets). Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2025 Pension Cost**
Discount rate	(0.5)	$ 100.7	$ 6.6
Discount rate	0.5	(90.8)	(7.5)
Rate of return on plan assets	(0.5)	N/A	13.1
Rate of return on plan assets	0.5	N/A	(13.1)

The following table shows how a given change in certain actuarial assumptions would impact the accumulated OPEB obligation and the reported net periodic OPEB cost (including amounts capitalized to our balance sheets). Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Postretirement Benefit Obligation**	**Impact on 2025 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 25.9	$ 2.1
Discount rate	0.5	(23.3)	(2.4)
Health care cost trend rate	(0.5)	(15.4)	(3.3)
Health care cost trend rate	0.5	17.4	3.1
Rate of return on plan assets	(0.5)	N/A	4.2
Rate of return on plan assets	0.5	N/A	(4.2)

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable, high-quality corporate bonds across the full maturity spectrum. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on assets based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return on pension plan assets was 6.61% in 2025 and 2024, and 6.62% in 2023. The actual rate of return on pension plan assets, net of fees, was 9.23%, 4.75%, and 9.23%, in 2025, 2024, and 2023, respectively.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and OPEB, see Note 20, Employee Benefits.

Unbilled Revenues

We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated.

Unbilled revenues are estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses, and applicable customer rates. Energy demand for the unbilled period or changes in rate mix due to fluctuations in usage patterns of customer classes could impact the accuracy of the unbilled revenue estimate. Total unbilled utility revenues were $667.5 million and $567.2 million as of December 31, 2025 and 2024, respectively. The changes in unbilled revenues are primarily due to changes in the cost of natural gas, weather, and customer rates.

Income Tax Expense

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(q), Income Taxes, and Note 16, Income Taxes, for a discussion of accounting for income taxes.

We are required to estimate income taxes for each of our applicable tax jurisdictions as part of the process of preparing consolidated financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to income tax expense in our income statements.

Uncertainty associated with the application of tax statutes and regulations, the outcomes of tax audits and appeals, changes in income tax law, enacted tax rates or amounts subject to income tax, and changes in the regulatory treatment of any tax reform benefits requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

We expect our 2026 annual effective tax rate to be between 5.5% and 6.5%. Our effective tax rate calculations are revised every quarter based on the best available year-end tax assumptions, adjusted in the following year after returns are filed. Tax accrual estimates are trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, as well as Note 1(r), Fair Value Measurements, Note 1(s), Derivative Instruments, and Note 19, Guarantees, for information concerning potential market risks to which we are exposed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matter

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

Regulatory Assets and Liabilities - Impact of rate regulation on financial statements — Refer to Notes 6 and 26 to the financial statements

Critical Audit Matter Description

The Company's regulated utilities are subject to regulation by various state and federal regulatory bodies (collectively the "Commissions") which have jurisdiction with respect to the rates of electric and gas utility companies in each respective state. Management has determined the Company meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the Regulated Operations Topic of the Financial Accounting Standards Board's Accounting Standard Codification.

Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Current and future regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered through rates. The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by the Company's regulators. 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: (1) full recovery of the costs of providing utility service, (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment or (3) timely recovery of costs incurred.

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 the impacted account balances and disclosures and the subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and/or (2) a refund to customers. Auditing these judgments required 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 impact of rate regulation on certain assets and liabilities included the following procedures, among others:

- We tested the effectiveness of management's controls over regulatory assets and liabilities, including management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred reported 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 monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.

- We inquired of Company management and independently obtained and read: (1) relevant regulatory orders issued by the Commissions for the Company, (2) Company filings with the Commissions, (3) filings made by intervenors and (4) 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. To assess completeness, we evaluated the information obtained and compared it to management's recorded regulatory asset and liability balances.

- For regulatory matters in process, we inquired of Company management and inspected the Company's filings with the Commissions, intervenor filings with the Commissions that may impact the Company's future rates, and correspondence between the Company and intervenors for any evidence that might contradict management's assertions.

- We evaluated management's conclusions regarding the probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order.

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

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 20, 2026

We have served as the Company's auditor since 2002.

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2025, of the Company and our report dated February 20, 2026, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

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 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

Milwaukee, Wisconsin
February 20, 2026

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions, except per share amounts)*	2025	2024	2023
Operating revenues	**$ 9,800.1**	$ 8,599.9	$ 8,893.0
Operating expenses			
Cost of sales	**3,265.8**	2,656.0	3,191.2
Other operation and maintenance	**2,400.8**	2,158.0	2,100.5
Impairments related to Illinois segment	**130.0**	12.1	178.9
Depreciation and amortization	**1,478.5**	1,354.5	1,264.2
Property and revenue taxes	**280.1**	266.5	250.2
Total operating expenses	**7,555.2**	6,447.1	6,985.0
Operating income	**2,244.9**	2,152.8	1,908.0
Equity in earnings of transmission affiliates	**215.8**	207.5	177.5
Other income, net	**107.9**	178.2	177.7
Interest expense	**895.1**	815.3	727.4
Gain on debt extinguishments	**—**	(23.1)	(0.5)
Other expense	**(571.4)**	(406.5)	(371.7)
Income before income taxes	**1,673.5**	1,746.3	1,536.3
Income tax expense	**118.0**	222.0	204.6
Net income	**1,555.5**	1,524.3	1,331.7
Preferred stock dividends of subsidiary	**1.2**	1.2	1.2
Net loss attributed to noncontrolling interests	**3.2**	4.1	1.2
Net income attributed to common shareholders	**$ 1,557.5**	$ 1,527.2	$ 1,331.7
EPS			
Basic	**$ 4.84**	$ 4.83	$ 4.22
Diluted	**$ 4.81**	$ 4.83	$ 4.22
Weighted average common shares outstanding			
Basic	**321.9**	316.2	315.4
Diluted	**323.8**	316.5	315.9

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 ***(in millions)***	**2025**	**2024**	**2023**
Net income	**$ 1,555.5**	$ 1,524.3	$ 1,331.7
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of realized derivative gains to net income, net of tax	**(0.2)**	(0.3)	(0.3)
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**0.2**	0.1	(0.6)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.2**	0.1	—
Defined benefit plans, net	**0.4**	0.2	(0.6)
Other comprehensive income (loss), net of tax	**0.2**	(0.1)	(0.9)
Comprehensive income	**1,555.7**	1,524.2	1,330.8
Preferred stock dividends of subsidiary	**1.2**	1.2	1.2
Comprehensive loss attributed to noncontrolling interests	**3.2**	4.1	1.2
Comprehensive income attributed to common shareholders	**$ 1,557.7**	$ 1,527.1	$ 1,330.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

D. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share amounts)*	2025	2024
Assets		
Current assets		
Cash and cash equivalents	**$ 27.6**	$ 9.8
Accounts receivable and unbilled revenues, net of reserves of $148.7 and $162.8, respectively	**2,062.7**	1,669.3
Materials, supplies, and inventories	**803.4**	813.2
Prepaid taxes	**178.8**	214.9
Other prepayments	**92.4**	82.6
Other	**119.8**	121.9
Current assets	**3,284.7**	2,911.7
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $12,411.5 and $11,611.9, respectively	**38,278.1**	34,645.4
Regulatory assets (December 31, 2025 and December 31, 2024 include $67.5 and $76.5, respectively, related to WEPCo Environmental Trust)	**3,156.3**	3,339.7
Equity investment in transmission affiliates	**2,280.4**	2,108.9
Goodwill	**3,052.8**	3,052.8
Pension and OPEB assets	**1,082.4**	968.5
Other	**383.6**	336.2
Long-term assets	**48,233.6**	44,451.5
Total assets	**$ 51,518.3**	$ 47,363.2
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 1,924.7**	$ 1,116.6
Current portion of long-term debt (December 31, 2025 and December 31, 2024 include $9.3 and $9.2, respectively, related to WEPCo Environmental Trust)	**1,519.4**	1,729.0
Accounts payable	**1,140.1**	1,137.1
Other	**1,009.2**	859.2
Current liabilities	**5,593.4**	4,841.9
Long-term liabilities		
Long-term debt (December 31, 2025 and December 31, 2024 include $67.4 and $76.4, respectively, related to WEPCo Environmental Trust)	**18,498.1**	17,178.1
Finance lease obligations	**372.0**	303.3
Deferred income taxes	**5,891.7**	5,514.7
Deferred revenue, net	**314.2**	334.6
Regulatory liabilities	**4,121.3**	3,958.0
Intangible liabilities	**580.3**	566.8
Environmental remediation liabilities	**484.1**	445.8
AROs	**647.0**	580.0
Other	**963.4**	838.1
Long-term liabilities	**31,872.1**	29,719.4
Commitments and contingencies (Note 24)		
Common shareholders' equity		
Common stock – $0.01 par value; 650,000,000 shares authorized; 325,461,519 and 317,680,855 shares outstanding, respectively	**3.3**	3.2
Additional paid in capital	**5,124.4**	4,315.8
Retained earnings	**8,493.5**	8,083.8
Accumulated other comprehensive loss	**(7.6)**	(7.8)
Common shareholders' equity	**13,613.6**	12,395.0
Preferred stock of subsidiary	**30.4**	30.4
Noncontrolling interests	**408.8**	376.5
Total liabilities and equity	**$ 51,518.3**	$ 47,363.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2025	2024	2023
Operating activities			
Net income	**$ 1,555.5**	$ 1,524.3	$ 1,331.7
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**1,478.5**	1,354.5	1,264.2
Deferred income taxes and ITCs, net	**368.5**	529.0	219.4
Impairments related to Illinois segment	**130.0**	12.1	178.9
Contributions and payments related to pension and OPEB plans	**(13.7)**	(14.5)	(16.7)
Equity income in transmission affiliates, net of distributions	**(29.2)**	(57.4)	(33.0)
Change in –			
Accounts receivable and unbilled revenues, net	**(411.8)**	(161.5)	340.6
Materials, supplies, and inventories	**9.8**	(38.0)	41.9
Prepaid taxes	**36.1**	(41.0)	27.9
Collateral on deposit	**(25.4)**	84.3	22.1
Other current assets	**11.4**	(34.4)	8.4
Accounts payable	**46.4**	99.7	(254.0)
Amounts refundable to customers	**43.6**	(2.2)	(9.0)
Other current liabilities	**86.5**	13.8	56.5
Other, net	**93.2**	(56.9)	(160.5)
Net cash provided by operating activities	**3,379.4**	3,211.8	3,018.4
Investing activities			
Capital expenditures	**(4,398.1)**	(2,781.1)	(2,492.9)
Acquisition of Hardin III, net of cash acquired of $0.2	**(406.1)**	—	—
Acquisition of Delilah I, net of cash acquired of $0.6	**—**	(462.5)	—
Acquisition of Maple Flats, net of cash acquired of $0.5	**—**	(431.2)	—
Acquisition of West Riverside	**—**	(97.9)	(95.3)
Acquisition of Red Barn	**—**	(2.1)	(143.8)
Acquisition of Whitewater	**—**	—	(76.0)
Acquisition of Sapphire Sky, net of cash acquired of $0.3	**—**	—	(442.6)
Acquisition of Samson I, net of cash acquired of $5.2	**—**	—	(257.3)
Capital contributions to transmission affiliates	**(142.4)**	(45.5)	(63.7)
Reimbursement for ATC's transmission infrastructure upgrades	**39.8**	8.1	0.1
Other, net	**32.1**	9.7	13.3
Net cash used in investing activities	**(4,874.7)**	(3,802.5)	(3,558.2)
Financing activities			
Exercise of stock options	**39.1**	23.7	6.3
Issuance of common stock, net	**761.9**	163.4	—
Purchase of common stock	**(1.3)**	(3.2)	(16.6)
Dividends paid on common stock	**(1,147.8)**	(1,056.2)	(984.2)
Issuance of long-term debt	**2,844.5**	4,460.9	2,170.0
Retirement of long-term debt	**(1,728.9)**	(2,138.0)	(1,005.4)
Change in commercial paper	**806.9**	(902.8)	373.7
Purchase of additional ownership interest in Samson I from noncontrolling interest	**—**	(28.1)	—
Payments for debt extinguishment and issuance costs	**(39.9)**	(45.9)	(14.2)
Other, net	**(10.5)**	(6.1)	(6.8)
Net cash provided by financing activities	**1,524.0**	467.7	522.8
Net change in cash, cash equivalents, and restricted cash	**28.7**	(123.0)	(17.0)
Cash, cash equivalents, and restricted cash at beginning of year	**42.2**	165.2	182.2
Cash, cash equivalents, and restricted cash at end of year	**$ 70.9**	$ 42.2	$ 165.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

F. CONSOLIDATED STATEMENTS OF EQUITY

	WEC Energy Group Common Shareholders' Equity							
(in millions, except per share amounts)	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interests	Total Equity
Balance at December 31, 2022	$ 3.2	$ 4,115.2	$ 7,265.3	$ (6.8)	$ 11,376.9	$ 30.4	$ 209.3	$ 11,616.6
Net income attributed to common shareholders	—	—	1,331.7	—	1,331.7	—	—	1,331.7
Net loss attributed to noncontrolling interests	—	—	—	—	—	—	(1.2)	(1.2)
Other comprehensive loss	—	—	—	(0.9)	(0.9)	—	—	(0.9)
Common stock dividends of $3.12 per share	—	—	(984.2)	—	(984.2)	—	—	(984.2)
Exercise of stock options	—	6.3	—	—	6.3	—	—	6.3
Purchase of common stock	—	(16.6)	—	—	(16.6)	—	—	(16.6)
Acquisition of noncontrolling interests	—	—	—	—	—	—	114.9	114.9
Distributions to noncontrolling interests	—	—	—	—	—	—	(6.0)	(6.0)
Stock-based compensation and other	—	11.0	—	—	11.0	—	(0.1)	10.9
Balance at December 31, 2023	$ 3.2	$ 4,115.9	$ 7,612.8	$ (7.7)	$ 11,724.2	$ 30.4	$ 316.9	$ 12,071.5
Net income attributed to common shareholders	—	—	1,527.2	—	1,527.2	—	—	1,527.2
Net loss attributed to noncontrolling interests	—	—	—	—	—	—	(4.1)	(4.1)
Other comprehensive loss	—	—	—	(0.1)	(0.1)	—	—	(0.1)
Issuance of common stock, net	—	163.4	—	—	163.4	—	—	163.4
Common stock dividends of $3.34 per share	—	—	(1,056.2)	—	(1,056.2)	—	—	(1,056.2)
Exercise of stock options	—	23.7	—	—	23.7	—	—	23.7
Purchase of common stock	—	(3.2)	—	—	(3.2)	—	—	(3.2)
Acquisition of noncontrolling interests	—	—	—	—	—	—	99.4	99.4
Purchase of additional ownership interest in Samson I from noncontrolling interest	—	4.3	—	—	4.3	—	(32.4)	(28.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	(3.3)	(3.3)
Stock-based compensation and other	—	11.7	—	—	11.7	—	—	11.7
Balance at December 31, 2024	$ 3.2	$ 4,315.8	$ 8,083.8	$ (7.8)	$ 12,395.0	$ 30.4	$ 376.5	$ 12,801.9
Net income attributed to common shareholders	**—**	**—**	**1,557.5**	**—**	**1,557.5**	**—**	**—**	**1,557.5**
Net loss attributed to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(3.2)**	**(3.2)**
Other comprehensive income	**—**	**—**	**—**	**0.2**	**0.2**	**—**	**—**	**0.2**
Issuance of common stock, net	**0.1**	**761.8**	**—**	**—**	**761.9**	**—**	**—**	**761.9**
Common stock dividends of $3.57 per share	**—**	**—**	**(1,147.8)**	**—**	**(1,147.8)**	**—**	**—**	**(1,147.8)**
Exercise of stock options	**—**	**39.1**	**—**	**—**	**39.1**	**—**	**—**	**39.1**
Purchase of common stock	**—**	**(1.3)**	**—**	**—**	**(1.3)**	**—**	**—**	**(1.3)**
Acquisition of noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**45.1**	**45.1**
Distributions to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(9.6)**	**(9.6)**
Stock-based compensation and other	**—**	**9.0**	**—**	**—**	**9.0**	**—**	**—**	**9.0**
Balance at December 31, 2025	**$ 3.3**	**$ 5,124.4**	**$ 8,493.5**	**$ (7.6)**	**$ 13,613.6**	**$ 30.4**	**$ 408.8**	**$ 14,052.8**

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—WEC Energy Group serves approximately 1.7 million electric customers and 3.0 million natural gas customers, owns approximately 60% of ATC, and owns majority interests in multiple renewable generating facilities as part of its non-utility energy infrastructure segment.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, statements of cash flows, and statements of equity, unless otherwise noted. On our financial statements, we consolidate our majority-owned subsidiaries, which we control, and VIEs, of which we are the primary beneficiary. We reflect noncontrolling interests for the portion of entities that we do not own as a component of consolidated equity separate from the equity attributable to our shareholders. The noncontrolling interests that we reported as equity on our balance sheet as of December 31, 2025 related to the minority interests held by third parties in the renewable generating facilities that are included in our non-utility energy infrastructure segment.

Our financial statements include the accounts of WEC Energy Group, a diversified energy holding company, and the accounts of our subsidiaries in the following reportable segments:

- Wisconsin segment – Consists of WE, WPS, and WG, which are engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin; and UMERC, which generates electricity and distributes electricity and natural gas to customers located in the Upper Peninsula of Michigan.

- Illinois segment – Consists of PGL and NSG, which are engaged primarily in the distribution of natural gas in Illinois.

- Other states segment – Consists of MERC and MGU, which are engaged primarily in the distribution of natural gas in Minnesota and Michigan, respectively.

- Electric transmission segment – Consists of our approximate 60% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions, and our approximate 75% ownership interest in ATC Holdco, which invests in transmission-related projects outside of ATC's traditional footprint.

- Non-utility energy infrastructure segment – Consists of We Power, which is principally engaged in the ownership of electric power generating facilities for long-term lease to WE, and Bluewater, which owns underground natural gas storage facilities in Michigan. WECI, which holds our majority interests in multiple renewable generating facilities, is also included in this segment. See Note 2, Acquisitions, for more information on recently acquired WECI renewable generating facilities.

- Corporate and other segment – Consists of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Wisvest, WECC, and WBS.

Investments in companies not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method. We use the cumulative earnings approach for classifying distributions received in the statements of cash flows. Under the cumulative earnings approach, we compare the distributions received to cumulative equity method earnings since inception. Any distributions received up to the amount of cumulative equity earnings are considered a return on investment and classified in operating activities. Any excess distributions are considered a return of investment and classified in investing activities.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 8, Jointly-Owned Utility Facilities, for more information.

(b) Basis of Presentation—We prepare our financial statements in conformity with GAAP. We make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities with an original maturity of three months or less.

(d) Operating Revenues—The following discussion includes our significant accounting policies related to operating revenues. For additional required disclosures on disaggregation of operating revenues, see Note 4, Operating Revenues.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

Electricity sales to residential and commercial and industrial customers are generally accomplished through requirements contracts, which provide for the delivery of as much electricity as the customer needs. These contracts represent discrete deliveries of electricity and consist of one distinct performance obligation satisfied over time, as the electricity is delivered and consumed by the customer simultaneously. For our Wisconsin residential and commercial and industrial customers and the majority of our Michigan residential and commercial and industrial customers, our performance obligation is bundled to consist of both the sale and the delivery of the electric commodity. In our Michigan service territory, a limited number of residential and commercial and industrial customers can purchase the commodity from a third party. In this case, the delivery of the electricity represents our sole performance obligation.

The transaction price of the performance obligations for residential and commercial and industrial customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated electric utilities, which have been approved by state regulators. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on the quantity of electricity delivered each month. Our retail electric rates in Wisconsin include base amounts for fuel and purchased power costs, which also impact our revenues. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs beyond a 2% price variance from the costs included in the rates charged to customers. Our electric utilities monitor the deferral of under-collected costs to ensure that it does not cause them to earn a greater ROE than authorized by the PSCW. In contrast, the rates of our Michigan retail electric customers include recovery of fuel and purchased power costs on a one-for-one basis. In addition, the Wisconsin residential tariffs of WE and WPS include a mechanism for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates.

Wholesale customers who resell power can choose to either bundle capacity and electricity services together under one contract with a supplier or purchase capacity and electricity separately from multiple suppliers. Furthermore, wholesale customers can choose to have our utilities provide generation to match the customer's load, similar to requirements contracts, or they can purchase specified quantities of electricity and capacity. Contracts with wholesale customers that include capacity bundled with the delivery of electricity contain two performance obligations, as capacity and electricity are often transacted separately in the marketplace at the wholesale level. When recognizing revenue associated with these contracts, the transaction price is allocated to each performance obligation based on its relative standalone selling price. Revenue is recognized as control of each individual component is transferred to the customer. Electricity is the primary product sold by our electric utilities and represents a single performance obligation satisfied over time through discrete deliveries to a customer. Revenue from electricity sales is generally recognized as units are produced and delivered to the customer within the production month. Capacity represents the reservation of an electric generating facility and conveys the ability to call on a plant to produce electricity when needed by the customer. The nature of our performance obligation as it relates to capacity is to stand ready to deliver power. This represents a single performance obligation transferred over time, which generally represents a monthly obligation. Accordingly, capacity revenue is recognized on a monthly basis.

The transaction price of the performance obligations for wholesale customers is valued using the rates, charges, terms, and conditions of service, which have been approved by the FERC. These wholesale rates include recovery of fuel and purchased power costs from customers on a one-for-one basis. For the majority of our wholesale customers, the price billed for energy and capacity is a formula-based rate. Formula-based rates initially set a customer's current year rates based on the previous year’s expenses. This is a predetermined formula derived from the utility's costs and a reasonable rate of return. Because these rates are eventually trued up to reflect actual current-year costs, they represent a form of variable consideration in certain circumstances. The variable consideration is estimated and recognized over time as wholesale customers receive and consume the capacity and electricity services.

We are an active participant in the MISO Energy Markets, where we bid our generation into the Day Ahead and Real Time markets and procure electricity for our retail and wholesale customers at prices determined by the MISO Energy Markets. Purchase and sale transactions are recorded using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded as purchased power in cost of sales, and net sales in a single hour are recorded as resale revenues on our income statements. For resale revenues, our performance obligation is created only when electricity is sold into the MISO Energy Markets.

For all of our customers, consistent with the timing of when we recognize revenue, customer billings generally occur on a monthly basis, with payments typically due in full within 30 days.

Natural Gas Utility Operating Revenues

We recognize natural gas utility operating revenues under requirements contracts with residential, commercial and industrial, and transportation customers served under the tariffs of our regulated utilities. Tariffs provide our customers with the standard terms and conditions, including rates, related to the services offered. Requirements contracts provide for the delivery of as much natural gas as the customer needs. These requirements contracts represent discrete deliveries of natural gas and constitute a single performance obligation satisfied over time. Our performance obligation is both created and satisfied with the transfer of control of natural gas upon delivery to the customer. For most of our customers, natural gas is delivered and consumed by the customer simultaneously. A performance obligation can be bundled to consist of both the sale and the delivery of the natural gas commodity. In certain of our service territories, customers can purchase the commodity from a third party. In this case, the performance obligation only includes the delivery of the natural gas to the customer.

The transaction price of the performance obligations for our natural gas customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated utilities, which have been approved by state regulators. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on natural gas delivered each month.

The tariffs of our natural gas utilities include various rate mechanisms that allow them to recover or refund changes in prudently incurred costs from rate case-approved amounts. The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs. Under normal circumstances, we defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

In addition, the rates of PGL and NSG, and the residential tariffs of WE, WPS, and WG, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The rates of PGL and NSG include riders for cost recovery of both environmental cleanup costs and energy conservation and management program costs. Finally, through the end of 2023 and effective again starting January 1, 2025, the rates of MGU include a rider to recover costs incurred to replace or modify natural gas facilities.

Consistent with the timing of when we recognize revenue, customer billings generally occur on a monthly basis, with payments typically due in full within 30 days.

Other Natural Gas Operating Revenues

We have other natural gas operating revenues from Bluewater, which is in our non-utility energy infrastructure segment. Bluewater owns underground natural gas storage facilities in southeastern Michigan and provides natural gas storage and hub services to customers. Bluewater has entered into long-term service agreements for natural gas storage services with WE, WPS, and WG, and also provides limited service to unaffiliated customers. We recognize revenues using a time-based output method through a monthly fixed service fee. Typical storage contract rates consist of firm storage reservation charges and firm injection and withdrawal charges. All amounts associated with the service agreements with WE, WPS, and WG have been eliminated at the consolidated level.

Other Non-Utility Operating Revenues

Wind and solar generation revenues from WECI's ownership interests in renewable generation facilities continued to grow in 2025. See Note 2, Acquisitions, for more information on recent acquisitions. Most of these renewable generation facilities have offtake agreements with unaffiliated third parties for all of the energy to be produced by the facility, some of which are bundled with capacity and RECs. We consider bundled energy, capacity, and RECs within these offtake agreements to be distinct performance obligations as each are often transacted separately in the marketplace.

When recognizing revenue associated with these contracts, the transaction price is allocated to each performance obligation based on its relative standalone selling price. Revenue is recognized as control of each individual component is transferred to the customer. Revenue from the sale of this renewable energy is generally recognized as units are produced and delivered to the customer within the production month. Capacity represents the reservation of the renewable generation facility and conveys the ability to call on the renewable generation facility to produce electricity when needed by the customer. The nature of our performance obligation as it relates to capacity is to stand ready to deliver power. This represents a single performance obligation transferred over time, which generally represents a monthly obligation. Accordingly, capacity revenue is recognized on a monthly basis. The performance obligation for RECs is recognized at a point-in-time; however, the timing of revenue recognition is the same, as the generation of renewable energy and the recognition of REC revenues generally occur concurrently.

Non-utility operating revenues are also derived from servicing appliances for customers at MERC. These contracts customarily have a duration of one year or less and consist of a single performance obligation satisfied over time. We use a time-based output method to recognize revenues monthly for the service fee.

Consistent with the timing of when we recognize revenue, customer billings for the renewable generation and servicing revenues generally occur on a monthly basis, with payments typically due in full within 30 days.

As part of the construction of the We Power electric generating units, we capitalized interest during construction, which is included in property, plant, and equipment. As allowed by the PSCW, we collected these carrying costs from WE's utility customers during construction. The equity portion of these carrying costs was recorded as a contract liability, which is presented as deferred revenue, net on our balance sheets. We continually amortize the deferred carrying costs to revenues over the related lease term that We Power has with WE. During 2025, 2024, and 2023, we recorded $24.6 million, $24.3 million, and $23.5 million, respectively, of revenues related to these deferred carrying costs.

Other Operating Revenues

Bespoke Resources Current Return

We recognize revenues monthly associated with carrying costs, including financing costs, during the construction period of bespoke resources assigned to WE's very large utility customers under payment and cancellation agreements. These amounts are not considered revenues from contracts with customers as electricity is not yet being provided by WE. Consistent with the timing of when we recognize revenue, customer billings for the bespoke resources that are subject to current return (as opposed to AFUDC) occur on a monthly basis, with payments typically due in full within 45 days.

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow our utilities to record additional revenues by adjusting rates in the future, usually as a surcharge applied to future billings, in response to past activities or completed events. Alternative revenue programs allow compensation for the effects of weather abnormalities, other external factors, or demand side management initiatives. Alternative revenue programs can also provide incentive awards if the utility achieves certain objectives and in other limited circumstances. We record alternative revenues when the regulator-specified conditions for recognition have been met. We reverse these alternative revenues as the customer is billed, at which time this revenue is presented as revenues from contracts with customers.

Below is a summary of the alternative revenue programs at our utilities:

- The rates of PGL, NSG, and MERC include decoupling mechanisms. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes.
- MERC’s rates include a conservation improvement program rider, which includes a financial incentive for meeting energy savings goals.
- WE and WPS provide wholesale electric service to customers under market-based rates and FERC formula rates. The customer is charged a base rate each year based upon a formula using prior year actual costs and customer demand. A true-up is calculated based on the difference between the amount billed to customers for the demand component of their rates and what the actual

cost of service was for the year. The true-up can result in an amount that we will recover from or refund to the customer. We consider the true-up portion of the wholesale electric revenues to be alternative revenues.

(e) Credit Losses—The following discussion includes our significant accounting policies related to credit losses. For additional required disclosures on credit losses, see Note 5, Credit Losses.

Our exposure to credit losses is related to our accounts receivable and unbilled revenue balances, which are primarily generated from the sale of electricity and natural gas by our regulated utility operations. Credit losses associated with our utility operations are analyzed at the reportable segment level as we believe contract terms, political and economic risks, and the regulatory environment are similar at this level as our reportable segments are generally based on the geographic location of the underlying utility operations.

We have an accounts receivable and unbilled revenue balance associated with our non-utility energy infrastructure segment, related to the sale of electricity from our majority-owned renewable generating facilities through agreements with several large high credit quality counterparties.

We evaluate the collectability of our accounts receivable and unbilled revenue balances considering a combination of factors. For some of our larger customers and also in circumstances where we become aware of a specific customer's inability to meet its financial obligations to us, we record a specific allowance for credit losses against amounts due in order to reduce the net recognized receivable to the amount we reasonably believe will be collected. For all other customers, we use the accounts receivable aging method to calculate an allowance for credit losses. Using this method, we classify accounts receivable into different aging buckets and calculate a reserve percentage for each aging bucket based upon historical loss rates. The calculated reserve percentages are updated on at least an annual basis, in order to ensure recent macroeconomic, political, and regulatory trends are captured in the calculation, to the extent possible. Risks identified that we do not believe are reflected in the calculated reserve percentages, are assessed on a quarterly basis to determine whether further adjustments are required.

We monitor our ongoing credit exposure through active review of counterparty accounts receivable balances against contract terms and due dates. Our activities include timely account reconciliation, dispute resolution and payment confirmation. To the extent possible, we work with customers with past due balances to negotiate payment plans, but will disconnect customers for non-payment as allowed by our regulators, if necessary, and employ collection agencies and legal counsel to pursue recovery of defaulted receivables. For our larger customers, detailed credit review procedures may be performed in advance of any sales being made. We sometimes require letters of credit, parental guarantees, prepayments or other forms of credit assurance from our larger customers, including VLCs, to mitigate credit risk.

(f) Materials, Supplies, and Inventories—Our inventories as of December 31 consisted of:

(in millions)	**2025**	2024
Materials and supplies	**$ 416.4**	$ 412.5
Natural gas in storage	**292.5**	300.2
Fossil fuel	**94.5**	100.5
Total	**$ 803.4**	$ 813.2

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 17% and 18% of total inventories at December 31, 2025 and 2024, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2025 and 2024, exceeded the LIFO cost by $94.9 million and $77.9 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.36 at December 31, 2025, and $3.10 at December 31, 2024.

Substantially all other materials and supplies, natural gas in storage, and fossil fuel inventories are recorded using the weighted-average cost method of accounting.

(g) Regulatory Assets and Liabilities—The economic effects of regulation can result in regulated companies recording costs and revenues that are allowed in the ratemaking process in a period different from the period they would have been recognized by a nonregulated company. When this occurs, regulatory assets and liabilities are recorded on the balance sheet. Regulatory assets represent deferred costs probable of recovery from customers that would have otherwise been charged to expense. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or future costs already collected from customers in rates.

The recovery or refund of regulatory assets and liabilities is based on specific periods determined by our regulators or occurs over the normal operating period of the related assets and liabilities. If a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery, and the reduction is charged to expense in the current period. See Note 6, Regulatory Assets and Liabilities, for more information.

(h) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and both debt and equity components of AFUDC. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to other operation and maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates approved by the applicable regulators. Annual utility composite depreciation rates are shown below:

Annual Utility Composite Depreciation Rates	**2025**	**2024**	**2023**
WE	**3.07%**	3.03%	3.03%
WPS	**3.01%**	2.92%	2.93%
WG	**2.45%**	2.61%	2.61%
PGL	**3.34%**	3.36%	3.13%
NSG	**2.49%**	2.49%	2.46%
MERC	**2.62%**	2.60%	2.60%
MGU	**2.87%**	2.87%	2.73%
UMERC	**3.20%**	3.01%	2.97%

We depreciate our We Power assets over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2 and 10 to 55 years for ER 1 and ER 2.

We depreciate our WECI assets over the estimated useful life of the property, with wind and solar generating facilities being depreciated over 30 and 35 years, respectively.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

Third parties reimburse the utilities for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs are recorded as a reduction to property, plant, and equipment.

See Note 7, Property, Plant, and Equipment, for more information.

(i) Allowance for Funds Used During Construction—AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC-Debt) used during plant construction, and a return on shareholders' capital (AFUDC-Equity) used for construction purposes. AFUDC-Debt is recorded as a reduction of interest expense, and AFUDC-Equity is recorded in other income, net.

The majority of AFUDC is recorded at WE, WPS, WG, UMERC, and WBS. Approximately 50% of WE's, WPS's, WG's, UMERC's, and WBS's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. AFUDC rates are determined by their respective state commissions, each with specific requirements. Average AFUDC rates are shown below:

	2025	
	Average AFUDC Retail Rate	**Average AFUDC Wholesale Rate**
WE	**8.65%**	**7.51%**
WPS	**7.82%**	**6.62%**
WG	**8.54%**	**N/A**
UMERC	**6.40%**	**N/A**
WBS	**7.82%**	**N/A**

Our regulated utilities and WBS recorded the following AFUDC for the years ended December 31:

(in millions)	2025	2024	2023
AFUDC-Debt			
WE	**$ 29.8**	$ 14.6	$ 13.0
WPS	**4.7**	3.6	2.9
UMERC	**3.4**	0.4	—
WG	**0.5**	0.5	3.4
WBS	**0.2**	0.1	0.1
Other	**0.4**	0.2	0.1
Total AFUDC-Debt	**$ 39.0**	$ 19.4	$ 19.5
AFUDC-Equity			
WE	**$ 78.9**	$ 46.0	$ 41.0
WPS	**12.2**	9.2	7.6
UMERC	**6.3**	1.0	—
WG	**1.2**	2.9	9.8
WBS	**0.5**	0.3	0.4
Other	**0.7**	0.4	0.3
Total AFUDC-Equity	**$ 99.8**	$ 59.8	$ 59.1

See Note 16, Income Taxes, for more information on how AFUDC-Equity is treated for tax purposes and the related impact on total WEC Energy Group income tax expense.

(j) Cloud Computing Hosting Arrangements that are Service Contracts—We have entered into several cloud computing arrangements that are hosted service contracts as part of projects related to the continuous transformation of technology. These projects include, among other things, a centralized repository for data to improve analytics, reporting, work and asset management, targeted enterprise resource planning systems, human resources management, employee scheduling, geospatial information, training, information technology service management, and customer contact systems. We present prepaid hosting fees that are service contracts in either prepayments or other long-term assets on our balance sheets and amortize them as the hosting services are received. Amortization expense, as well as the fees associated with the hosting arrangements, is recorded in other operation and maintenance expense on our income statements.

At December 31, 2025 and 2024, we had $27.0 million and $17.0 million, respectively, of capitalized implementation costs related to cloud computing arrangements that are hosted service contracts. We amortize the implementation costs on a straight-line basis over the cloud computing service arrangement term once the component of the hosted service is ready for its intended use. Accumulated amortization at December 31, 2025 and 2024, was $5.8 million and $4.1 million, respectively. Amortization expense for the years ended December 31, 2025, 2024, and 2023 was not significant. The presentation of the implementation costs, along with the related accumulated amortization, follows the prepaid hosting fees.

(k) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. During the third quarter of each year, we perform an annual impairment test for all of our reporting units that carried a goodwill balance. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit's net assets exceeds the reporting unit's fair value. An impairment loss is recorded as the excess of the carrying amount of the goodwill over its fair value. For our indefinite-lived intangible assets, an impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds its fair value. An impairment loss is measured as the excess of the carrying amount of the intangible asset over its fair value. No impairment losses were recorded for our indefinite-lived intangible assets during the years ended December 31, 2025, 2024, and 2023. See Note 10, Goodwill and Intangibles, for more information.

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. Long-lived assets that would be subject to an impairment assessment generally include any assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, as well as assets within nonregulated operations that are proposed to be sold or are currently generating operating losses. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset over its fair value.

We also periodically assess the recoverability of our non-utility long-lived assets, which includes reviewing current activities, changes in the conditions of our renewable generating facilities, and market conditions in which they operate to determine the existence of any indicators requiring an impairment analysis. Indicators of potential impairment for a non-utility long-lived asset group, generally an individual renewable generation project, include adverse changes in the financial condition of a customer to our offtake agreements, a significant decline in the forecasted operating revenues and earnings of our renewable generation projects, and deterioration in the performance of our renewable generation projects.

We assess the likelihood of a disallowance of part of the cost of recently completed plant by considering factors such as applicable regulatory environment changes, our own recent rate orders, as well as recent rate orders of other regulated entities in similar jurisdictions. When it becomes probable that part of the cost of recently completed plant will be disallowed for rate-making purposes, we assess whether a reasonable estimate of the amount of the disallowance can be made. The estimated amount of the probable disallowance will then be deducted from the reported cost of the plant and recognized as an impairment loss.

When it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. If a generating unit meets the applicable criteria to be considered probable of abandonment, and the unit has been abandoned, we assess the likelihood of recovery of the remaining net book value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of a generating unit that is either abandoned or probable of being abandoned, an impairment loss may be required. An impairment loss would be recorded if the remaining net book value of the generating unit is greater than the present value of the amount expected to be recovered from ratepayers, using an incremental borrowing rate. See Note 6, Regulatory Assets and Liabilities, and Note 7, Property, Plant, and Equipment, for more information.

We periodically assess the recoverability of equity method investments when factors indicate the carrying amount of such assets may be impaired. Equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts if a fair value assessment was completed or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

We recorded the following impairment losses on our income statements in the following segments during the years ended December 31:

(in millions)	**2025**	**2024**	**2023**
Illinois	**$ 130.0** [1]	$ 12.1 [2]	$ 178.9 [3]
Non-utility energy infrastructure [4]	**15.9**	—	—
Total impairment losses	**$ 145.9**	$ 12.1	$ 178.9

[1] Represents a probable disallowance of certain capital costs at PGL under the QIP rider. See Note 26, Regulatory Environment, for more information.

(2) Represents a disallowance of certain previously incurred capital costs at PGL resulting from an ICC order received in August 2024 related to the 2016 annual prudency review of the QIP rider. See Note 26, Regulatory Environment, for more information.

(3) Represents a disallowance of certain previously incurred capital costs resulting from PGL's and NSG's November 2023 rate orders from the ICC. See Note 26, Regulatory Environment, for more information.

(4) Represents impairment losses related to storm damage at certain of WECI's renewable generation facilities.

(l) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted each period using the credit-adjusted risk-free interest rates associated with the expected settlement dates of the AROs. These rates are determined when the obligations are incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated capitalized retirement costs. For our regulated entities, we recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 9, Asset Retirement Obligations, for more information.

(m) Finite-Lived Intangible Asset and Liabilities—Our finite-lived intangible asset and liabilities include revenue contracts, consisting of PPAs and a proxy revenue swap, in addition to interconnection agreements, which resulted from the acquisitions of renewable generation facilities by WECI in our non-utility energy infrastructure segment. Intangible asset and liabilities are amortized on a straight-line basis over their estimated useful lives, which is the term of the related agreement. Amortization of the revenue intangible asset and liabilities are recorded within operating revenues in the income statements. Amortization of the interconnection agreement intangible liabilities is recorded within other operation and maintenance in the income statements. The straight-line method of amortization is used because it best reflects the pattern in which the economic benefits of the intangibles are consumed or otherwise used. The amounts and useful lives assigned to the intangible asset and liabilities assumed impact the amount and timing of future amortization. See Note 10, Goodwill and Intangibles, for more information.

(n) Stock-Based Compensation—In accordance with the Omnibus Stock Incentive Plan, we provide long-term incentives through our equity interests to our non-employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in common stock, cash, or a combination thereof. In addition to those shares of common stock that were subject to awards outstanding as of May 6, 2021, when the plan was last approved by shareholders, 9.0 million shares were reserved for issuance under the plan.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period. We account for forfeitures as they occur.

Stock Options

We grant non-qualified stock options that generally vest on a cliff-basis after three years. The exercise price of a stock option under the plan cannot be less than 100% of our common stock's fair market value on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of our common stock on the date of the grant. Options vest immediately upon retirement, death, or disability; however, they may not be exercised within six months of the grant date except in connection with certain termination of employment events following a change in control. Options expire no later than 10 years from the date of the grant.

Our stock options are classified as equity awards. The fair value of our stock options was calculated using a binomial option-pricing model. The following table shows the estimated weighted-average fair value per stock option granted along with the weighted-average assumptions used in the valuation models:

	2025	2024	2023
Stock options granted	**231,024**	294,990	257,780
Estimated weighted-average fair value per stock option	**$ 18.23**	$ 16.19	$ 19.58
Assumptions used to value the options:			
Risk-free interest rate	**4.2% – 4.6%**	3.9% – 5.4%	3.8% – 4.8%
Dividend yield	**4.1 %**	3.8 %	3.2 %
Expected volatility	**22.0 %**	22.0 %	22.0 %
Expected life (years)	**8.3**	8.4	8.3

The risk-free interest rate was based on the United States Treasury interest rate with a term consistent with the expected life of the stock options. The dividend yield was based on our dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on our historical experience.

Restricted Shares

Restricted shares granted to employees generally have a vesting period of three years with one-third of the award vesting on each anniversary of the grant date. Restricted shares granted to non-employee directors fully vest after one year.

Our restricted shares are classified as equity awards.

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. All grants of performance units are settled in cash and are accounted for as liability awards accordingly. Performance units accrue forfeitable dividend equivalents in the form of additional performance units. The fair value of the performance units reflects our estimate of the final expected value of the awards, which is based on our stock price and performance achievement under the terms of the award. Stock-based compensation costs are generally recorded over the performance period, which is three years.

Pursuant to the terms of the WEC Energy Group Performance Unit Plan, the Compensation Committee selected multiple performance measures that will be weighted to determine the ultimate payout of the performance unit awards. The ultimate number of units that will be paid out will be based on our total shareholder return compared to the total shareholder return of a peer group of companies over three years (55%), and our performance against the weighted average authorized ROE of all of our utility subsidiaries (45%). In addition, the Compensation Committee selected the level of our stock price to earnings ratio compared to our peer companies as a performance measure that can increase the payout by up to 25%. In no event can the performance unit payout be greater than 200% of the target award.

See Note 11, Common Equity, for more information on our stock-based compensation plans.

(o) Earnings Per Share—We compute basic EPS by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed in a similar manner, but includes the exercise, settlement, and/or conversion of all potentially dilutive securities. Our potentially dilutive securities include stock options, forward equity sales contracts, and shares issuable upon the conversion of our convertible debt instruments.

The dilutive impacts from our in-the-money stock options and forward equity sales contract are calculated using the treasury stock method. The calculation of diluted EPS for the year ended December 31, 2025 excluded 58,533 shares issuable under our forward equity sales contract as their effect was anti-dilutive. The calculation of diluted EPS for the years ended December 31, 2024 and 2023 excluded 66,870 and 1,716,286 stock options, respectively, that had an anti-dilutive effect. No stock options had an anti-dilutive effect for the year ended December 31, 2025, and we did not have any forward equity sales contracts prior to 2025.

Potentially dilutive common shares issuable upon conversion of our convertible debt instruments are calculated using the if-converted method. For the year ended December 31, 2025, there were no shares of our common stock related to the potential conversion of the 2028 Notes (issued in June 2025) included in our diluted EPS calculation as the impact was anti-dilutive. For the year ended December 31, 2024, there were no shares of our common stock related to the potential conversion of the 2027 Notes and 2029 Notes (both issued in 2024) included in our diluted EPS calculation as the impact was anti-dilutive.

See Note 11, Common Equity, for more information on the computation of our basic and diluted EPS.

(p) Leases—We recognize a right of use asset and lease liability for operating and finance leases with a term of greater than one year. As a policy election, we account for each lease component separately from the nonlease components of a contract.

We are currently party to several easement agreements that allow us access to land we do not own for the purpose of constructing and maintaining certain electric power and natural gas equipment. The majority of payments we make related to easements relate to our renewable generating facilities. We have not classified our easements as leases because we view the entire parcel of land specified in our easement agreements to be the identified asset, not just that portion of the parcel that contains our easement. As such, we have concluded that we do not control the use of an identified asset related to our easement agreements, nor do we obtain substantially all of the economic benefits associated with these shared-use assets.

See Note 15, Leases, for more information.

(q) Income Taxes—In December 2023, the FASB issued ASU No. 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The amendments require additional disclosures, primarily related to income taxes paid and the rate reconciliation table. The amendments require disclosures on specific categories in the rate reconciliation table, as well as additional information for reconciling items that meet a quantitative threshold. For income taxes paid, additional disclosures are required to disaggregate federal, state, and foreign income taxes paid, with additional disclosures for income taxes paid that meet a quantitative threshold. We adopted ASU No. 2023-09 on January 1, 2025, on a retroactive basis, with the required disclosures first included in our 2025 Annual Report on Form 10-K.

We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

ITCs are deferred and amortized over the life of the assets. PTCs are recognized in the period in which such credits are generated. The amount of the credit is based upon power production from our qualifying generation facilities. We file a consolidated federal income tax return. Accordingly, we allocate federal current tax expense, benefits, and credits to our subsidiaries based on their separate tax computations and our ability to monetize all credits on our consolidated federal return.

We recognize interest and penalties accrued, related to unrecognized tax benefits, in income tax expense in our income statements.

The IRA contains a tax credit transferability provision that allows us to sell PTCs and ITCs produced after December 31, 2022, to third parties. Under this transferability provision, we entered into agreements to sell the majority of the PTCs and ITCs we generated in 2023, 2024, and 2025 to third parties. See Note 16, Income Taxes, for more information on the PTCs we sold. We have also entered into an agreement to sell the majority of PTCs that we expect to generate in 2026 to third parties. We elect to account for tax credits transferred under the scope of ASC 740. We include the discount from the sale of tax credits as a component of income tax expense. We also include any expected proceeds from the sale of tax credits in the evaluation of the realizability of deferred tax assets related to PTCs and ITCs. The sale of tax credits is presented in the operating activities section of the statements of cash flows consistent with the presentation of cash taxes paid.

In April 2023, the IRS issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting that taxpayers may use to determine whether expenses to repair, maintain, replace, or improve natural gas transmission and distribution property must be capitalized for tax purposes. We adopted the safe harbor method of accounting for certain of our utilities on our 2023 tax return and adopted the safe harbor method of accounting for our remaining utilities on our 2024 tax return, which increased our deferred tax liabilities.

See Note 16, Income Taxes, for more information.

(r) Fair Value Measurements—Fair value is 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 (exit price).

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methods.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities. We primarily use a market approach for recurring fair value measurements and attempt to use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

When possible, we base the valuations of our assets and liabilities on quoted prices for identical assets and liabilities in active markets. These valuations are classified in Level 1. The valuations of certain contracts not classified as Level 1 may be based on quoted market prices received from counterparties and/or observable inputs for similar instruments. Transactions valued using these inputs are classified in Level 2. Certain derivatives, such as FTRs and TCRs, are categorized in Level 3 due to the significance of unobservable or internally-developed inputs. FTRs and TCRs are valued using auction prices from the applicable RTO.

See Note 17, Fair Value Measurements, for more information.

(s) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of interest rates, purchased power, generation, and natural gas costs for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk. Regulated hedging programs are approved by our state regulators.

We record derivative instruments on our balance sheets as assets or liabilities measured at fair value unless they qualify for the normal purchases and sales exception, and are so designated. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy-related physical and financial contracts in our regulated operations that qualify as derivatives, our regulators allow the effects of fair value accounting to be offset to regulatory assets and liabilities.

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets, and cash collateral received is reflected in other current liabilities. See Note 18, Derivative Instruments, for more information.

(t) Guarantees—We follow the guidance of the Guarantees Topic of the FASB ASC, which requires, under certain circumstances, that the guarantor recognize a liability for the fair value of the obligation undertaken in issuing the guarantee at its inception. See Note 19, Guarantees, for more information.

(u) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among our subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 20, Employee Benefits, for more information.

(v) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service. Customer deposits are recorded within other current liabilities on our balance sheets.

Utility customers can elect to be on a budget plan. Under this type of plan, a monthly installment amount is calculated based on estimated annual usage. During the year, the monthly installment amount is reviewed by comparing it to actual usage. If necessary, an adjustment is made to the monthly amount. Annually, the budget plan is reconciled to actual annual usage. Payments in excess of actual customer usage are recorded within other current liabilities on our balance sheets.

(w) Environmental Remediation Costs—We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party. Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including CCR landfills and manufactured gas plant sites. See Note 9, Asset Retirement Obligations, for more information regarding CCR landfills and Note 24, Commitments and Contingencies, for more information regarding manufactured gas plant sites.

We record environmental remediation liabilities when site assessments indicate remediation is probable, and we can reasonably estimate the loss or a range of losses. The estimate includes both our share of the liability and any additional amounts that will not be paid by other potentially responsible parties or the government. When possible, we estimate costs using site-specific information but also consider historical experience for costs incurred at similar sites. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, potentially affecting the cost of remediation.

Our utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the applicable state regulatory commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and CCR landfills. We adjust the liabilities and related regulatory assets, as appropriate, to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

(x) Customer Concentrations of Credit Risk—The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more counterparties could fail to perform their obligations, and we could recognize financial losses as a result. Credit risk exposure at WE, WPS, WG, PGL, and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed in Note 1(d), Operating Revenues. There were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2025.

As a result, for the majority of our utility companies, we did not have any significant concentrations of credit risk at December 31, 2025. However, WE has contracts with a small number of customers to provide power to large-scale data centers to support AI and other technology capabilities. This concentration of business with a small number of customers in an industry based on emerging technologies presents several risks. WE is incurring significant costs to construct bespoke resources to serve these customers. Although WE requires these customers to enter into payment and cancellation agreements, WE may still experience significant losses or delayed recovery of these costs. Changes in industry practice or advances in these technologies could reduce the demand for electricity to power data centers, which would reduce our forecasted revenues. Significant capital spend to build out required infrastructure or a downturn in business could weaken their financial condition, liquidity and/or creditworthiness, including their ability to satisfy their reimbursement obligations to us.

NOTE 2—ACQUISITIONS

In accordance with Topic 805: Clarifying the Definition of a Business (ASU 2017-01), transactions are evaluated and are accounted for as acquisitions of assets or businesses, and transaction costs are capitalized in asset acquisitions. It was determined that all of the below acquisitions met the criteria of asset acquisitions. The purchase price of certain acquisitions below includes intangibles recorded as long-term assets and long-term liabilities related to PPAs. See Note 10, Goodwill and Intangibles, for more information.

Acquisition of a Solar Generation Facility in Ohio

Upon commercial operation in February 2025, WECI completed the acquisition of a 90% ownership interest in Hardin III, a 250 MW solar generating facility located in Hardin County, Ohio for $406.1 million. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 15 years from the date of commercial operation. Hardin III qualifies for PTCs and is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)	
Net property, plant, and equipment	$ 526.5
Other current assets	0.2
Other current liabilities	(0.4)
Other long-term liabilities	(75.1)
Noncontrolling interest	(45.1)
Total purchase price	$ 406.1

Acquisitions of Solar Generation Facilities in Texas

Upon commercial operation in December 2024, WECI completed the acquisition of a 90% ownership interest in Delilah I, a 300 MW solar generating facility in Lamar, Franklin, Hopkins, and Red River counties in Texas. Delilah I was acquired for $462.5 million, which included transaction costs and was net of cash acquired. The project has offtake agreements for all of the energy to be produced by the facility for a period of 15 years from the date of commercial operation. Delilah I qualifies for PTCs and is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)	
Other current assets	$ 0.1
Net property, plant, and equipment	579.8
Other long-term assets	12.4
Other long-term liabilities	(78.3)
Noncontrolling interest	(51.5)
Total purchase price	$ 462.5

In February 2023, WECI completed the acquisition of an 80% ownership interest in Samson I, a commercially operational 250 MW solar generating facility in Lamar, Franklin, Hopkins, and Red River counties in Texas. Samson I was acquired for $257.3 million, which included transaction costs and was net of cash acquired. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 15 years from the date of commercial operation in May 2022. Samson I qualifies for PTCs and is included in the non-utility energy infrastructure segment. In January 2024, WECI acquired an additional 10% ownership interest in Samson I for $28.1 million.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the original acquisition.

(in millions)		
Accounts receivable	$	0.5
Other current assets		0.7
Net property, plant, and equipment		497.2
Other long-term assets		12.3
Accounts payable		(0.5)
Other current liabilities		(0.8)
Other long-term liabilities		(186.4)
Noncontrolling interest		(65.7)
Total purchase price	$	257.3

Acquisitions of Electric Generation Facilities in Illinois

Upon commercial operation in November 2024, WECI completed the acquisition of a 90% ownership interest in Maple Flats, a 250 MW solar generating facility in Clay County, Illinois. Maple Flats was acquired for $431.2 million, which included transaction costs and was net of cash acquired. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 15 years from the date of commercial operation. Maple Flats qualifies for PTCs and is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)		
Net property, plant, and equipment	$	469.5
Other long-term assets		44.5
Other long-term liabilities		(34.9)
Noncontrolling interest		(47.9)
Total purchase price	$	431.2

In February 2023, upon achievement of commercial operation, WECI completed the acquisition of a 90% ownership interest in Sapphire Sky, a 250 MW wind generating facility in McLean County, Illinois, for a total investment of $442.6 million, which includes transaction costs and is net of cash acquired. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 12 years from the date of commercial operation. Sapphire Sky qualifies for PTCs and is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)		
Accounts receivable	$	0.8
Net property, plant, and equipment		642.6
Other long-term assets		1.4
Accounts payable		(1.0)
Other long-term liabilities		(152.0)
Noncontrolling interest		(49.2)
Total purchase price	$	442.6

Acquisitions of Electric Generation Facilities in Wisconsin

In December 2025, WE and WPS, along with an unaffiliated utility, signed an agreement to acquire Whitetail, a wind-powered electric generation project with a total capacity of 67.2 MW. This project will be located in Grant County, Wisconsin and WE will own 80% and WPS will own 10%. WE's share of the purchase price is expected to be approximately $178 million and WPS's share of the purchase price is expected to be approximately $22 million. The project is expected to close in late 2027 and it is expected to qualify for PTCs.

In May 2024, WE completed the acquisition of an additional 100 MWs of West Riverside's nameplate capacity for $97.9 million. West Riverside is a commercially operational dual fueled combined cycle generation facility in Beloit, Wisconsin. In June 2023, WE completed the first acquisition of 100 MWs for $95.3 million. After the second acquisition, WE owns 200 MWs, or 27.5%, of West Riverside at a total cost of $193.2 million.

In April 2023, WPS, along with an unaffiliated utility, completed the acquisition of Red Barn, a commercially operational utility-scale wind-powered electric generating facility. The project is located in Grant County, Wisconsin and WPS owns 82 MWs of this project. WPS's share of the cost of this project was $145.9 million. Red Barn qualifies for PTCs.

In January 2023, WE and WPS completed the acquisition of Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electric generation facility in Whitewater, Wisconsin, for $76.0 million.

NOTE 3—DISPOSITION

Wisconsin Segment

Sale of Certain Real Estate by Wisconsin Electric Power Company

In June 2023, we sold approximately 192 acres of real estate at WE's former Pleasant Prairie power plant site that was no longer being utilized in its operations, for $23.0 million, which is net of closing costs. As a result of the sale, a pre-tax gain in the amount of $22.2 million was recorded within other operation and maintenance expense on our income statement. The book value of the real estate included in the sale was not material and, therefore, was not presented as held for sale.

NOTE 4—OPERATING REVENUES

For more information about our significant accounting policies related to operating revenues, see Note 1(d), Operating Revenues.

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We do not have any revenues associated with our electric transmission segment, which includes investments accounted for using the equity method. We disaggregate revenues into categories that depict how the nature, amount, timing, and uncertainty of revenues and cash flows are affected by economic factors. For our segments, revenues are further disaggregated by electric and natural gas operations and then by customer class. Each customer class within our electric and natural gas operations has different expectations of service, energy and demand requirements, and can be impacted differently by regulatory activities within their jurisdictions.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Year ended December 31, 2025								
Electric	**$ 5,529.6**	**$ —**	**$ —**	**$ 5,529.6**	**$ —**	**$ —**	**$ —**	**$ 5,529.6**
Natural gas	**1,741.6**	**1,717.6**	**508.1**	**3,967.3**	**47.0**	**—**	**(44.5)**	**3,969.8**
Total regulated revenues	**7,271.2**	**1,717.6**	**508.1**	**9,496.9**	**47.0**	**—**	**(44.5)**	**9,499.4**
Other non-utility revenues	**—**	**—**	**21.8**	**21.8**	**243.6**	**—**	**(9.2)**	**256.2**
Total revenues from contracts with customers	**7,271.2**	**1,717.6**	**529.9**	**9,518.7**	**290.6**	**—**	**(53.7)**	**9,755.6**
Other operating revenues	**24.3**	**(34.0)**	**(2.4)**	**(12.1)**	**479.6**	**—**	**(423.0)** [1]	**44.5**
Total operating revenues	**$ 7,295.5**	**$ 1,683.6**	**$ 527.5**	**$ 9,506.6**	**$ 770.2**	**$ —**	**$ (476.7)**	**$ 9,800.1**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Year ended December 31, 2024								
Electric	$ 4,908.4	$ —	$ —	$ 4,908.4	$ —	$ —	$ —	$ 4,908.4
Natural gas	1,402.4	1,499.6	419.7	3,321.7	48.4	—	(46.0)	3,324.1
Total regulated revenues	6,310.8	1,499.6	419.7	8,230.1	48.4	—	(46.0)	8,232.5
Other non-utility revenues	—	—	20.4	20.4	223.9	—	(9.1)	235.2
Total revenues from contracts with customers	6,310.8	1,499.6	440.1	8,250.5	272.3	—	(55.1)	8,467.7
Other operating revenues	19.7	102.8	9.7	132.2	419.0	—	(419.0) [1]	132.2
Total operating revenues	$ 6,330.5	$ 1,602.4	$ 449.8	$ 8,382.7	$ 691.3	$ —	$ (474.1)	$ 8,599.9

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Year Ended December 31, 2023								
Electric	$ 4,994.6	$ —	$ —	$ 4,994.6	$ —	$ —	$ —	$ 4,994.6
Natural gas	1,606.7	1,480.5	493.7	3,580.9	61.9	—	(60.2)	3,582.6
Total regulated revenues	6,601.3	1,480.5	493.7	8,575.5	61.9	—	(60.2)	8,577.2
Other non-utility revenues	—	—	19.6	19.6	197.5	0.1	(9.1)	208.1
Total revenues from contracts with customers	6,601.3	1,480.5	513.3	8,595.1	259.4	0.1	(69.3)	8,785.3
Other operating revenues	24.6	77.3	5.8	107.7	407.1	—	(407.1) [1]	107.7
Total operating revenues	$ 6,625.9	$ 1,557.8	$ 519.1	$ 8,702.8	$ 666.5	$ 0.1	$ (476.4)	$ 8,893.0

[1] Amounts eliminated represent lease revenues related to certain plants that We Power leases to WE to supply electricity to its customers. Lease payments are billed from We Power to WE and then recovered in WE's rates as authorized by the PSCW and the FERC. WE operates the plants and is authorized by the PSCW and Wisconsin state law to fully recover prudently incurred operating and maintenance costs in electric rates.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

The following table disaggregates electric utility operating revenues into customer class:

	Year Ended December 31		
(in millions)	2025	2024	2023
Residential	**$ 2,249.6**	$ 1,996.3	$ 1,992.3
Small commercial and industrial	**1,763.6**	1,613.0	1,641.1
Large commercial and industrial	**1,057.8**	942.6	978.4
Other	**30.9**	30.2	30.5
Total retail revenues	**5,101.9**	4,582.1	4,642.3
Wholesale	**107.6**	102.6	120.4
Resale	**267.6**	176.7	195.4
Steam	**28.4**	22.4	25.2
Other utility revenues	**24.1**	24.6	11.3
Total electric utility operating revenues	**$ 5,529.6**	$ 4,908.4	$ 4,994.6

Natural Gas Utility Operating Revenues

The following tables disaggregate natural gas utility operating revenues into customer class:

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year ended December 31, 2025				
Residential	**$ 1,100.2**	**$ 1,174.9**	**$ 316.5**	**$ 2,591.6**
Commercial and industrial	**563.9**	**320.0**	**164.4**	**1,048.3**
Total retail revenues	**1,664.1**	**1,494.9**	**480.9**	**3,639.9**
Transportation	**105.1**	**291.8**	**38.8**	**435.7**
Other utility revenues [(1)] [(2)]	**(27.6)**	**(69.1)**	**(11.6)**	**(108.3)**
Total natural gas utility operating revenues	**$ 1,741.6**	**$ 1,717.6**	**$ 508.1**	**$ 3,967.3**

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year ended December 31, 2024				
Residential	$ 893.1	$ 945.5	$ 250.5	$ 2,089.1
Commercial and industrial	416.8	274.5	123.9	815.2
Total retail revenues	1,309.9	1,220.0	374.4	2,904.3
Transportation	96.8	272.2	33.6	402.6
Other utility revenues [(1)]	(4.3)	7.4	11.7	14.8
Total natural gas utility operating revenues	$ 1,402.4	$ 1,499.6	$ 419.7	$ 3,321.7

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(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2023				
Residential	$ 1,012.0	$ 966.0	$ 324.4	$ 2,302.4
Commercial and industrial	506.7	267.1	175.3	949.1
Total retail revenues	1,518.7	1,233.1	499.7	3,251.5
Transportation	93.0	231.9	32.5	357.4
Other utility revenues [1]	(5.0)	15.5	(38.5)	(28.0)
Total natural gas utility operating revenues	$ 1,606.7	$ 1,480.5	$ 493.7	$ 3,580.9

[1] Includes the revenues subject to the purchased gas recovery mechanisms of our utilities, which fluctuate by segment based on actual natural gas costs incurred at our utilities, compared with the recovery of natural gas costs that were anticipated in rates.

[2] For our Illinois segment, includes a $75.0 million reduction in revenues recorded in the fourth quarter of 2025 for future billing credits to customers, based on the terms of a proposed settlement in February 2026 to resolve open QIP and UEA proceedings.

Other Non-Utility Operating Revenues

Other non-utility operating revenues consist primarily of the following:

	Year Ended December 31		
(in millions)	**2025**	**2024**	**2023**
Renewable generation revenues	**$ 209.8**	$ 190.5	$ 164.9
We Power revenues	**24.6**	24.3	23.5
Appliance service revenues	**21.8**	20.4	19.6
Other	**—**	—	0.1
Total other non-utility operating revenues	**$ 256.2**	$ 235.2	$ 208.1

Other Operating Revenues

Other operating revenues consist primarily of the following:

	Year Ended December 31		
(in millions)	**2025**	**2024**	**2023**
Late payment charges	**$ 48.1**	$ 48.5	$ 56.5
Bespoke resources current return [1]	**4.1**	—	—
Alternative revenues [2]	**(67.7)**	79.8	47.0
Other	**60.0**	3.9	4.2
Total other operating revenues	**$ 44.5**	$ 132.2	$ 107.7

[1] Bespoke resources current return consists of carrying costs earned during the construction of bespoke resources assigned to WE's VLCs. See Note 1(d), Operating Revenues, for more information.

[2] Alternative revenues consist of amounts to be recovered or refunded to customers subject to decoupling mechanisms, wholesale true-ups, and conservation improvement rider true-ups. Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. For more information about our alternative revenues, see Note 1(d), Operating Revenues.

NOTE 5—CREDIT LOSSES

We have included tables below that show our gross third-party receivable balances and the related allowance for credit losses at December 31, 2025 and 2024, by reportable segment.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	WEC Energy Group Consolidated
December 31, 2025							
Accounts receivable and unbilled revenues	**$ 1,368.8**	**$ 654.8**	**$ 130.2**	**$ 2,153.8**	**$ 50.3**	**$ 7.3**	**$ 2,211.4**
Allowance for credit losses	**61.7**	**82.3**	**4.7**	**148.7**	**—**	**—**	**148.7**
Accounts receivable and unbilled revenues, net (1)	**$ 1,307.1**	**$ 572.5**	**$ 125.5**	**$ 2,005.1**	**$ 50.3**	**$ 7.3**	**$ 2,062.7**
Total accounts receivable, net – past due greater than 90 days (1)	**$ 46.4**	**$ 36.8**	**$ 6.6**	**$ 89.8**	**$ —**	**$ —**	**$ 89.8**
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms (1)	**94.6 %**	**100.0 %**	**— %**	**89.9 %**	**— %**	**— %**	**89.9 %**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	WEC Energy Group Consolidated
December 31, 2024							
Accounts receivable and unbilled revenues	$ 1,149.9	$ 535.6	$ 100.6	$ 1,786.1	$ 40.0	$ 6.0	$ 1,832.1
Allowance for credit losses	73.6	83.9	5.3	162.8	—	—	162.8
Accounts receivable and unbilled revenues, net (1)	$ 1,076.3	$ 451.7	$ 95.3	$ 1,623.3	$ 40.0	$ 6.0	$ 1,669.3
Total accounts receivable, net – past due greater than 90 days (1)	$ 51.8	$ 30.1	$ 2.5	$ 84.4	$ —	$ —	$ 84.4
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms (1)	93.8 %	100.0 %	— %	93.2 %	— %	— %	93.2 %

(1) Our exposure to credit losses for certain regulated utility customers is mitigated by regulatory mechanisms we have in place. Specifically, rates related to all of the customers in our Illinois segment, as well as the residential rates of WE, WPS, and WG in our Wisconsin segment, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between the actual provision for credit losses and the amounts recovered in rates. As a result, at December 31, 2025, $1,290.2 million, or 62.5%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses. See Note 26, Regulatory Environment, for more information on PGL and NSG's UEA rider for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and amounts recovered in rates.

A rollforward of the allowance for credit losses by reportable segment for the years ended December 31, 2025, 2024, and 2023, is included below:

(in millions)	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at January 1, 2025	**$ 73.6**	**$ 83.9**	**$ 5.3**	**$ 162.8**
Provision for credit losses	**85.0**	**55.8**	**2.0**	**142.8**
Provision for credit losses deferred for future recovery or refund	**4.9**	**(28.7)**	**—**	**(23.8)**
Write-offs charged against the allowance	**(151.4)**	**(81.2)**	**(8.4)**	**(241.0)**
Recoveries of amounts previously written off	**49.6**	**52.5**	**5.8**	**107.9**
Balance at December 31, 2025	**$ 61.7**	**$ 82.3**	**$ 4.7**	**$ 148.7**

On a consolidated basis, there was a $14.1 million decrease in the allowance for credit losses during the year ended December 31, 2025. This decrease is largely driven by customer write-offs in Wisconsin in addition to a decrease in past due account balances in Wisconsin that we believe was related to a continued focus on collection efforts and lower energy bills in the spring and summer months, enabling customers to pay down their arrears.

(in millions)	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at January 1, 2024	$ 77.4	$ 109.7	$ 6.4	$ 193.5
Provision for credit losses	52.1	52.3	0.5	104.9
Provision for credit losses deferred for future recovery or refund	43.8	(8.0)	—	35.8
Write-offs charged against the allowance	(141.8)	(95.0)	(6.6)	(243.4)
Recoveries of amounts previously written off	42.1	24.9	5.0	72.0
Balance at December 31, 2024	$ 73.6	$ 83.9	$ 5.3	$ 162.8

On a consolidated basis, there was a $30.7 million decrease in the allowance for credit losses during the year ended December 31, 2024, largely driven by customer write-offs. We also believe that the lower energy costs that customers were seeing, which were driven by warmer than normal weather conditions during most of 2024 and low average natural gas prices, contributed to a reduction in past due accounts receivable balances and a related decrease in the allowance for credit losses.

(in millions)	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at January 1, 2023	$ 82.0	$ 111.0	$ 6.3	$ 199.3
Provision for credit losses	40.9	26.3	4.8	72.0
Provision for credit losses deferred for future recovery or refund	52.5	35.8	—	88.3
Write-offs charged against the allowance	(131.6)	(85.4)	(6.6)	(223.6)
Recoveries of amounts previously written off	33.6	22.0	1.9	57.5
Balance at December 31, 2023	$ 77.4	$ 109.7	$ 6.4	$ 193.5

On a consolidated basis, there was a $5.8 million decrease in the allowance for credit losses during the year ended December 31, 2023, primarily related to lower customer energy costs (driven by the warmer weather during the fourth quarter of 2023 when compared to the same quarter in 2022 and lower natural gas prices), which contributed to a reduction in past due accounts receivable balances and a related decrease in the allowance for credit losses. Customer write-offs also contributed to the decrease in the allowance for credit losses.

NOTE 6—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets were reflected on our balance sheets as of December 31:

(in millions)	2025	2024	See Note
Regulatory assets [1] [2]			
Plant retirement related items [3]	**$ 768.6**	$ 810.5	
Environmental remediation costs [4]	**566.0**	570.1	24
Pension and OPEB costs [5]	**564.5**	684.9	20, 26
Income tax related items	**493.4**	438.5	16
AROs	**185.1**	166.7	1(l), 9
Uncollectible expense	**123.9**	151.5	5
SSR [6]	**92.6**	102.9	
Securitization	**67.5**	76.5	23
Derivatives	**57.7**	38.2	1(s)
Decoupling	**43.8**	110.0	1(d)
Bluewater [7]	**37.7**	57.7	
Finance and operating leases	**36.0**	22.0	15
Electric transmission costs [8]	**30.7**	0.4	
Energy efficiency programs [9]	**11.6**	26.5	
Other, net	**94.5**	122.3	
Total regulatory assets	**$ 3,173.6**	$ 3,378.7	
Balance sheet presentation			
Other current assets	**$ 17.3**	$ 39.0	
Regulatory assets	**3,156.3**	3,339.7	
Total regulatory assets	**$ 3,173.6**	$ 3,378.7	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in this table. In accordance with GAAP, our regulatory assets do not include the allowance for ROE that is capitalized for regulatory purposes. This allowance was $20.9 million and $26.7 million at December 31, 2025 and 2024, respectively.

(2) As of December 31, 2025, we had $183.1 million of regulatory assets not earning a return, $1.3 million of regulatory assets earning a return based on short-term interest rates, $106.1 million of regulatory assets earning a return based on long-term interest rates, and $5.5 million of regulatory assets earning a return based on the applicable utility's ROE. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, decoupling mechanisms, electric transmission costs, unamortized loss on reacquired debt, and uncollectible expense. The other regulatory assets in the table either earn a return at the applicable utility's weighted average cost of capital or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

(3) Primarily represents the net book value of power plants we have both abandoned and retired. For all of these plants, we have approval to collect a return of their remaining net book value. We also have approval to collect a return on all but $100 million of their remaining net book value. For information on the securitization of this $100 million, see Note 23, Variable Interest Entities. These regulatory assets are amortized on a straight-line basis, using the composite depreciation rates approved before the plants were retired, and the amortization is included in depreciation and amortization in the income statement.

(4) As of December 31, 2025, we had made cash expenditures of $81.9 million related to these environmental remediation costs. The remaining $484.1 million represents our estimated future cash expenditures.

(5) Primarily represents the unrecognized future pension and OPEB costs related to our defined benefit pension and OPEB plans. We are authorized recovery of these regulatory assets over the average remaining service life of each plan.

(6) This regulatory asset relates to WE's 2014 announcement to retire the PIPP. Despite WE's intent to retire the PIPP, MISO designated the PIPP as a SSR, which meant the PIPP's operation was necessary for reliability, and the plant could not be shut down until new generation or transmission facilities were built. In December 2014, the PSCW authorized escrow accounting for WE's SSR revenues because of the fluctuations in the actual revenues WE received under the PIPP SSR agreements. The rate order WE received from the PSCW in December 2019 authorized recovery of this SSR regulatory asset over a 15-year period that began on January 1, 2020.

(7) Primarily relates to costs associated with the long-term service agreements our Wisconsin utilities have with Bluewater for natural gas storage services. The PSCW has approved escrow accounting for these costs. As a result, our Wisconsin utilities defer as a regulatory asset or liability the difference between actual storage costs and those included in rates until recovery or refund is authorized in a future rate proceeding.

(8) In accordance with the PSCW's approval of escrow accounting for ATC and MISO network transmission expenses for our Wisconsin electric utilities, WE and WPS defer as a regulatory asset or liability the difference between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding.

(9) Represents amounts recoverable from customers related to programs at the utilities designed to meet energy efficiency standards.

The following regulatory liabilities were reflected on our balance sheets as of December 31:

(in millions)	2025	2024	See Note
Regulatory liabilities			
Income tax related items	**$ 1,802.4**	$ 1,825.4	16
Removal costs [1]	**1,584.7**	1,458.2	
Pension and OPEB benefits [2]	**301.5**	308.5	20, 26
Proposed settlement related to QIP and UEA riders	**125.0**	—	26
Energy costs refundable through rate adjustments	**119.2**	160.8	1(d)
Uncollectible expense	**73.1**	47.2	5
Earnings sharing mechanisms	**35.8**	7.1	26
Derivatives	**27.4**	36.9	1(s)
MERC property tax tracker [3]	**23.1**	19.3	
Revenue requirements of renewable generation facilities [4]	**14.5**	44.2	
Other, net	**103.5**	95.7	
Total regulatory liabilities	**$ 4,210.2**	$ 4,003.3	
Balance sheet presentation			
Other current liabilities	**$ 88.9**	$ 45.3	
Regulatory liabilities	**4,121.3**	3,958.0	
Total regulatory liabilities	**$ 4,210.2**	$ 4,003.3	

(1) Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required. Legal obligations related to the removal of property, plant, and equipment are recorded as AROs. See Note 9, Asset Retirement Obligations, for more information on our legal obligations.

(2) Primarily represents the unrecognized future pension and OPEB benefits related to our defined benefit pension and OPEB plans. We will amortize these regulatory liabilities into net periodic benefit cost over the average remaining service life of each plan.

(3) MERC defers as a regulatory asset or liability the difference between actual property tax expense and the amount included in rates until recovery or refund is authorized in a future rate proceeding.

(4) These amounts represent the deferral of the incremental revenue requirement impact from the delayed in-service date of certain renewable generation facilities constructed by our electric utilities.

Oak Creek Power Plant Units 5-6

In May 2024, OCPP Units 5 and 6 were retired. Due to the retirement of these units and the determination that recovery was probable, their net book value of $68.3 million at December 31, 2025 was classified as a regulatory asset. In addition, a $45.0 million cost of removal reserve related to the units continued to be classified as a regulatory liability at December 31, 2025. Not included in these amounts was $6.3 million of deferred tax liabilities previously recorded for the retired units. Effective with its rate order issued by the PSCW in December 2022, WE received approval to collect a return of and on the entire net book value of OCPP Units 5 and 6 and, as a result, will continue to amortize the regulatory asset on a straight-line basis, using the composite depreciation rates approved by the PSCW before the units were retired. The amortization is included in depreciation and amortization on the income statement. WE also has FERC approval to continue to collect the net book value of OCPP Units 5 and 6 using the approved composite depreciation rates, in addition to a return on the remaining net book value.

NOTE 7—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following at December 31:

(in millions)	2025	2024
Electric – generation	**$ 7,998.3**	$ 6,685.0
Electric – distribution	**10,048.9**	9,298.9
Natural gas – distribution, storage, and transmission	**16,175.0**	15,673.0
Property, plant, and equipment to be retired, net	**621.7**	906.3
Other	**2,431.2**	2,410.8
Less: Accumulated depreciation	**10,180.2**	9,401.0
Net	**27,094.9**	25,573.0
CWIP	**3,364.4**	1,653.6
Net utility and non-utility property, plant, and equipment	**30,459.3**	27,226.6
We Power generation	**3,250.7**	3,284.3
Renewable generation	**5,252.4**	4,720.8
Natural gas storage	**299.6**	298.6
Net non-utility energy infrastructure	**8,802.7**	8,303.7
Corporate services	**167.6**	172.3
Other	**11.3**	14.1
Less: Accumulated depreciation	**1,559.1**	1,393.9
Net	**7,422.5**	7,096.2
CWIP	**60.8**	41.3
Net other property, plant, and equipment	**7,483.3**	7,137.5
Property under finance leases	**351.8**	291.3
Less: Accumulated amortization	**16.3**	10.0
Net leased facilities	**335.5**	281.3
Total property, plant, and equipment	**$ 38,278.1**	$ 34,645.4

Severance Liability for Plant Retirements

We have severance liabilities related to past and future plant retirements recorded in other current and other long-term liabilities on our balance sheets. Activity related to these severance liabilities for the years ended December 31 was as follows:

(in millions)	2025	2024	2023
Severance liability at January 1	**$ 13.4**	$ 17.8	$ 16.2
Severance expense	**—**	(3.9) [(1)]	1.6
Severance payments	**(0.7)**	(0.5)	—
Total severance liability at December 31	**$ 12.7**	$ 13.4	$ 17.8

(1) The severance accrual was lowered in 2024 due to workforce realignment efforts.

Wisconsin Segment Plant to be Retired

Oak Creek Power Plant Units 7 and 8

As a result of a PSCW approval in December 2022 for the acquisition and construction of Darien, the retirement of OCPP Units 7 and 8 became probable. Subsequently, we have received PSCW approval for several other renewable and other projects and have also acquired additional projects. On June 25, 2025, we announced plans to extend the lives of OCPP Units 7 and 8, and expect to have the units available to meet high energy demand periods through the end of 2026. These units were originally scheduled to be retired at the end of 2025. The total net book value of WE's ownership share of OCPP Units 7 and 8 was $621.7 million at December 31, 2025, which does not include deferred taxes. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WE continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW.

Columbia Energy Center Units 1 and 2

As a result of a MISO ruling received in June 2021, retirement of the jointly-owned Columbia Units 1 and 2 became probable. Through June 30, 2025, Columbia Units 1 and 2 were expected to be retired by the end of 2029 and, therefore, met the criteria to be considered probable of abandonment.

In conjunction with our new capital plan, we and the other co-owners currently plan to continue coal operations at Columbia Units 1 and 2 through at least 2029, and continue to evaluate the conversion of both units to natural gas. As a result, we and the other co-owners concluded that Columbia Units 1 and 2 (net book value of WPS's ownership share of Columbia Units 1 and 2 was $236.8 million at December 31, 2025, which does not include deferred taxes) no longer meet the criteria necessary to be considered probable of abandonment.

At December 31, 2025, these units continue to be included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW.

Samson Solar Energy LLC and Delilah Solar Energy LLC – Storm Damage

During several storms that occurred in 2023 and 2024, certain sections of our Samson I solar facility incurred damage. We had previously recognized an impairment loss of $2.8 million related to damage from these storms, and recorded an offsetting $2.8 million receivable for future insurance recoveries. However, in the second quarter of 2025, we determined it was no longer probable that we would receive insurance proceeds sufficient to recover our losses associated with the 2023 and 2024 storms. As a result, the insurance receivable balance was written off, resulting in the recognition of the $2.8 million impairment loss within other operation and maintenance expense on our income statement.

In addition, in March 2025, both our Samson I and Delilah I solar facilities experienced damage from a storm. In the second quarter of 2025, we recognized an impairment loss within other operation and maintenance expense on our income statement in the amount of $8.8 million, related to damage incurred associated with the March 2025 storm. The impairment loss associated with the March 2025 storm was increased from $8.8 million to $12.0 million in the third quarter of 2025 as a result of ongoing damage assessment.

The Peoples Gas Light and Coke Company and North Shore Gas Company Impairments

In the fourth quarter of 2025, PGL recorded a $130.0 million impairment to property, plant, and equipment related to the terms of a proposed settlement that would resolve its open QIP proceedings.

In August 2024, the ICC issued a final order on PGL's 2016 QIP annual reconciliation, which included a disallowance of certain capital costs. As a result, we recorded a $12.1 million impairment to property, plant, and equipment in 2024.

In November 2023, the ICC issued written rate orders that disallowed $177.2 million of previously incurred capital costs related to the construction and improvement of PGL’s service centers and $1.7 million of capital costs related to NSG's construction of a gas infrastructure project. As a result of these disallowances, we recorded a $178.9 million non-cash impairment to property, plant, and equipment in 2023.

See Note 26, Regulatory Environment, for more information.

NOTE 8—JOINTLY-OWNED UTILITY FACILITIES

Our electric utilities hold joint ownership interests in certain electric generating facilities. We are entitled to our share of generating capability and output of each facility equal to our respective ownership interest. We have supplied our own financing for all jointly owned projects. We pay our ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit our maximum exposure to additional costs. We record our proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets. In addition, our proportionate share of direct expenses for the joint operation of these plants is recorded within operating expenses in the income statements.

Information related to jointly owned utility facilities in-service at December 31, 2025 was as follows:

Company	Jointly-Owned Utility Facilities	Ownership	Share of Capacity (MW)	In-Service /Acquisition Date	Operating Owner	Property, Plant, and Equipment	Accumulated Depreciation	CWIP
(in millions, except for percentages and MW)								
We Power [1]	ER 1 & ER 2 [2]	**83.34 %**	**1,083.4**	**2010 & 2011**	**WE**	**$ 2,489.4**	**$ (542.0)**	**$ 4.6**
WPS	Weston Unit 4 [2]	**70.0 %**	**379.8**	**2008**	**WPS**	**600.6**	**(242.7)**	**4.5**
WPS	Columbia Units 1 & 2 [2]	**27.5 %**	**306.2**	**1975 & 1978**	**WPL**	**439.1**	**(201.6)**	**5.0**
WPS	Forward Wind [3]	**44.6 %**	**61.5**	**2008**	**WPS**	**120.3**	**(63.3)**	**13.9**
WPS	Two Creeks [4]	**66.7 %**	**100.0**	**2020**	**WPS**	**135.7**	**(22.9)**	**—**
WPS	Badger Hollow I [4]	**66.7 %**	**100.0**	**2021**	**WPS**	**146.0**	**(19.0)**	**—**
WPS	Red Barn [3]	**90.0 %**	**82.4**	**2023**	**WPS**	**150.7**	**(12.8)**	**—**
WE	West Riverside [2] [5]	**27.5 %**	**190.2**	**2023 & 2024**	**WPL**	**223.6**	**(36.7)**	**2.2**
WE	Badger Hollow II [4]	**66.7 %**	**100.0**	**2023**	**WE**	**179.3**	**(11.8)**	**—**
WE, WPS	Paris Solar [4]	**90.0 %**	**180.0**	**2024**	**WE**	**359.3**	**(11.0)**	**—**
WE, WPS	Paris Battery	**90.0 %**	**99.0**	**2025**	**WE**	**236.8**	**(5.5)**	**—**
WE, WPS	Darien Solar [4]	**90.0 %**	**225.0**	**2025**	**WE**	**460.1**	**(10.7)**	**—**

(1) We Power leases its ownership interest in ER 1 and ER 2 to WE.

(2) Capacity is based on rated capacity, which is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. Values are primarily based on the net dependable expected capacity ratings for summer 2026 established by tests and may change slightly from year to year. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

(3) Capacity for wind generating facilities is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds.

(4) Capacity for solar generating facilities is based on nameplate capacity, which is the maximum output that a generator should produce at continuous full power.

(5) WE acquired a 13.8% ownership interest in June 2023 and acquired an additional 13.7% ownership interest in May 2024. See Note 2, Acquisitions, for more information.

Information related to jointly owned utility facilities approved by the PSCW at December 31, 2025 was as follows:

Company	Jointly-Owned Utility Facilities	Ownership	Share of Capacity (MW)	Date of Expected In-Service	CWIP
(in millions, except for percentages and MW)					
WE, WPS	Koshkonong Solar	**90.0 %**	**270.0**	**2026**	**$ 460.6**
WE, WPS	Koshkonong Battery	**90.0 %**	**149.0**	**2027**	**150.7**
WE, WPS	Darien Battery	**90.0 %**	**68.0**	**2027**	**68.3**
WE, WPS	High Noon Solar	**90.0 %**	**270.0**	**2027**	**404.2**
WE, WPS	High Noon Battery	**90.0 %**	**149.0**	**2027**	**150.8**
WE, WPS	Ursa Solar Electric Generation Facility	**90.0 %**	**180.0**	**2027**	**57.1**
WE, WPS	Saratoga Solar	**90.0 %**	**135.0**	**2028**	**39.2**
WE, WPS	Saratoga Battery	**90.0 %**	**45.0**	**2028**	**53.2**
WE, WPS	Badger Hollow Wind Energy Generation Facility	**90.0 %**	**100.0**	**2027**	**50.0**
WE, WPS	Whitetail	**90.0 %**	**60.0**	**2027**	**9.0**

NOTE 9—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and PCBs); asbestos abatement at certain generation and substation facilities, office buildings, and service centers; the removal and dismantlement of a biomass generation facility; the dismantling of wind and solar generation projects; the removal and dismantlement of a battery storage facility; the disposal of PCB-contaminated transformers; the closure of CCR landfills at certain generation facilities; and the removal of above ground and underground storage tanks. Regulatory assets and liabilities are established by our utilities to record the differences between ongoing expense recognition under the ARO accounting rules and the ratemaking practices for retirement costs authorized by the applicable regulators.

WECI has also recorded AROs for the dismantling of our non-utility renewable generation projects.

The following table shows changes to our AROs during the years ended December 31:

(in millions)	2025	2024	2023
Balance as of January 1	**$ 580.0**	$ 374.2	$ 479.3
Accretion	**26.6**	18.8	17.2
Additions	**29.6**	192.7 [1]	24.0
Revisions to estimated cash flows	**23.7**	6.4	(133.5) [2]
Liabilities settled	**(12.9)**	(12.1)	(12.8)
Balance as of December 31	**$ 647.0**	$ 580.0	$ 374.2

[1] AROs increased primarily as a result of AROs being recorded related to the new EPA CCR Rule that was enacted in April 2024. See Note 24, Commitments and Contingencies, for more information.

[2] AROs decreased primarily due to revisions made to estimated cash flows for changes in removal cost estimates and settlements dates for mains and services at PGL and NSG.

NOTE 10—GOODWILL AND INTANGIBLES

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The table below shows our goodwill balances by segment at December 31, 2025. We had no changes to the carrying amount of goodwill during the years ended December 31, 2025 and 2024.

(in millions)	Wisconsin	Illinois	Other States	Non-Utility Energy Infrastructure	Total
Goodwill [(1)]	**$ 2,104.3**	**$ 758.7**	**$ 183.2**	**$ 6.6**	**$ 3,052.8**

(1) We had no accumulated impairment losses related to our goodwill as of December 31, 2025.

During the third quarter of 2025, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2025. No impairments resulted from these tests.

Other Indefinite-Lived Intangible Assets

At December 31, 2025 and 2024, we had $44.4 million and $29.3 million, respectively, of other indefinite-lived intangible assets included in other long-term assets on our balance sheets. These assets consist of $24.1 million of spectrum frequencies, which enable our utilities to transmit data and voice communications over a wavelength dedicated to us throughout our service territories. We also have $5.2 million of other indefinite-lived intangible assets, consisting of a MGU trade name from a previous acquisition. In October 2025, we entered into an option agreement for exclusive rights to purchase land for future generation development in Wisconsin. We made the first annual option payment and incurred costs of $15.1 million during 2025, with a right to exercise our option on or before December 31, 2030.

Finite-Lived Intangible Asset

At December 31, 2025 and 2024, we had a finite-lived intangible asset with a gross carrying amount of $18.8 million and $13.0 million, respectively, related to a PPA for Maple Flats acquired by WECI in November 2024. The PPA will be amortized over a useful life of 15 years and expires in 2039. At December 31, 2025 and 2024, accumulated amortization related to the intangible asset was not material. This finite-lived intangible asset is included in other long-term assets on our balance sheet. Amortization expense related to the intangible asset was not material for the year ended December 31, 2025 and 2024. Amortization expense to be recorded as a decrease to operating revenues is expected to be $1.3 million in each of the next five years. See Note 2, Acquisitions, for more information on the acquisition of Maple Flats.

Intangible Liabilities

The intangible liabilities below were all obtained through acquisitions by WECI.

	December 31, 2025			December 31, 2024		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
PPAs [(1)]	**$ 751.2**	**$ (176.5)**	**$ 574.7**	$ 679.6	$ (119.3)	$ 560.3
Proxy revenue swap [(2)]	**7.2**	**(4.9)**	**2.3**	7.2	(4.2)	3.0
Interconnection agreements [(3)]	**4.7**	**(1.4)**	**3.3**	4.7	(1.2)	3.5
Total intangible liabilities	**$ 763.1**	**$ (182.8)**	**$ 580.3**	$ 691.5	$ (124.7)	$ 566.8

(1) Represents PPAs related to the acquisition of Blooming Grove, Tatanka Ridge, Jayhawk, Thunderhead, Samson I, Sapphire Sky, Delilah I, and Hardin III expiring between 2030 and 2040. The weighted-average remaining useful life of the PPAs is 10 years. See Note 2, Acquisitions, for more information on recent WECI acquisitions.

(2) Represents an agreement with a counterparty to swap the market revenue of Upstream's wind generation for fixed quarterly payments over 10 years, which expires in 2029. The remaining useful life of the proxy revenue swap is three years.

(3) Represents interconnection agreements related to the acquisitions of Tatanka Ridge and Bishop Hill III, expiring in 2040 and 2041, respectively. These agreements relate to payments for connecting our facilities to the infrastructure of another utility to facilitate the movement of power onto the electric grid. The weighted-average remaining useful life of the interconnection agreements is 15 years.

Amortization related to these intangible liabilities for the years ended December 31, 2025, 2024, and 2023 was $58.1 million, $53.7 million, and $50.6 million, respectively. Amortization for the next five years is estimated to be:

	For the Years Ending December 31				
(in millions)	**2026**	**2027**	**2028**	**2029**	**2030**
Amortization to be recorded as an increase to operating revenues	$ 59.9	$ 59.9	$ 59.9	$ 59.9	$ 59.9
Amortization to be recorded as a decrease to other operation and maintenance	0.2	0.2	0.2	0.2	0.2

NOTE 11—COMMON EQUITY

Stock-Based Compensation

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit recognized in income for the years ended December 31:

(in millions)	**2025**	**2024**	**2023**
Stock options	**$ 4.1**	$ 4.9	$ 5.3
Restricted stock	**6.2**	7.6	6.6
Performance units	**37.9**	26.8	(2.2) (1)
Stock-based compensation expense	**$ 48.2**	$ 39.3	$ 9.7
Related tax benefit	**$ 13.2**	$ 10.8	$ 2.7

(1) The reduction in expense was due to a decrease in the fair value of the outstanding performance units.

Stock-based compensation costs capitalized during 2025, 2024, and 2023 were not significant.

Stock Options

The following is a summary of our stock option activity during 2025:

Stock Options	**Number of Options**	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Life *(in years)***	**Aggregate Intrinsic Value *(in millions)***
Outstanding as of January 1, 2025	**2,916,902**	**$ 82.32**		
Granted	**231,024**	**94.55**		
Exercised	**(575,758)**	**67.92**		
Forfeited	**(1,351)**	**91.11**		
Expired	**(1,330)**	**52.90**		
Outstanding as of December 31, 2025	**2,569,487**	**86.65**	**5.3**	**$ 48.3**
Exercisable as of December 31, 2025	**1,937,953**	**85.29**	**4.4**	**$ 39.1**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2025. This is calculated as the difference between our closing stock price on December 31, 2025, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the years ended December 31, 2025, 2024, and 2023 was $22.8 million, $11.2 million, and $5.2 million, respectively. The tax benefit from option exercises for the same years was approximately $6.3 million, $3.1 million, and $1.4 million, respectively. These amounts do not account for the compensation limitations under Internal Revenue Code Section 162(m).

As of December 31, 2025, approximately $1.4 million of unrecognized compensation cost related to unvested and outstanding stock options was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2026, the Compensation Committee awarded 269,085 non-qualified stock options with a weighted-average exercise price of $106.09 and a weighted-average grant date fair value of $21.20 per option to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restricted Shares

The following restricted stock activity occurred during 2025:

Restricted Shares	**Number of Shares**	**Weighted-Average Grant Date Fair Value**
Outstanding and unvested as of January 1, 2025	105,242	$ 87.61
Granted	79,170	94.55
Released	(58,725)	88.48
Forfeited	(6,774)	90.88
Outstanding and unvested as of December 31, 2025	**118,913**	**91.61**

The intrinsic value of restricted stock released was $5.7 million, $8.6 million, and $5.8 million for the years ended December 31, 2025, 2024, and 2023, respectively. The tax benefit from released restricted shares for the same years was $1.6 million, $2.4 million, and $1.6 million, respectively. These amounts do not account for the compensation limitations under Internal Revenue Code Section 162(m).

As of December 31, 2025, approximately $4.9 million of unrecognized compensation cost related to unvested and outstanding restricted stock was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2026, the Compensation Committee awarded 75,222 restricted shares to certain of our directors, officers, and other key employees under its normal schedule of awarding long-term incentive compensation. The grant date fair value of these awards was $106.09 per share.

Performance Units

During 2025, 2024, and 2023, the Compensation Committee awarded 185,945; 205,051; and 157,035 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $15.4 million, $2.4 million, and $10.2 million were settled during 2025, 2024, and 2023, respectively. The tax benefit from the distribution of performance units for the same years was $3.8 million, $0.6 million, and $2.6 million, respectively.

At December 31, 2025, we had 502,733 performance units outstanding, including dividend equivalents. A liability of $57.1 million was recorded on our balance sheet at December 31, 2025 related to these outstanding units. As of December 31, 2025, approximately $31.3 million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2026, we settled performance units with an intrinsic value of $25.2 million. The tax benefit from the distribution of these awards was $5.7 million. This amount and the tax benefits disclosed above do not account for the compensation limitations under Internal Revenue Code Section 162(m). In January 2026, the Compensation Committee also awarded 182,146 performance units to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our utility subsidiaries, We Power, Bluewater, ATC Holding, and WECI. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. All of our utility subsidiaries, with the exception of UMERC and MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with their most recent rate orders, WE, WPS, and WG may not pay common dividends above the test year forecasted amounts reflected in their respective rate cases, if it would cause their average common equity ratio, on a financial basis, to fall below their authorized level of 53.0%. A return of capital in excess of the test year amount can be paid by each company at the end of the year provided that their respective average common equity ratios do not fall below the authorized level.

WE may not pay common dividends to us under WE's Restated Articles of Incorporation if any dividends on its outstanding preferred stock have not been paid. In addition, pursuant to the terms of WE's 3.60% Serial Preferred Stock, WE's ability to declare common dividends would be limited to 75% or 50% of net income during a 12-month period if its common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

The long-term debt obligations of UMERC, Bluewater Gas Storage, and ATC Holding contain a provision requiring them to maintain a total funded debt to capitalization ratio of 65% or less.

The long-term debt obligations of WECI Wind Holding I, WECI Wind Holding II, and WECI Energy Holding III contain various conditions that must be met prior to them making any cash distributions. Included in these provisions is a requirement to maintain a debt service coverage ratio of 1.2 or greater prior to the distribution.

WEC Energy Group has the option to defer interest payments on its 2024A Junior Notes, 2024B Junior Notes, and 2025 Junior Notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which it defers interest payments, it may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, its common stock.

See Note 13, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2025, restricted net assets of our consolidated subsidiaries totaled approximately $14 billion. Our equity in undistributed earnings of investees accounted for by the equity method was approximately $615 million.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Common Stock

As of January 1, 2024, we began issuing new shares of common stock to fulfill our obligations under various stock-based employee benefit and compensation plans and to provide shares to participants in our dividend reinvestment and stock purchase plan. During 2023, we instructed our independent agents to purchase shares on the open market to fulfill obligations under these plans. As such, no new shares of common stock were issued during the year ended December 31, 2023.

In August 2024, we entered into an EDA, under which we could offer and sell, from time to time, shares of our common stock having an aggregate sales price of up to $1.5 billion through an at-the-market offering program, which included an equity forward sales component. This EDA was terminated on October 31, 2025. Prior to its termination, we issued 7,610,457 shares of common stock under this EDA and received proceeds of $797.3 million, which was net of $9.2 million of commissions and other fees. We did not enter into any forward sales agreements under the August 2024 EDA.

In connection with our termination of the August 2024 EDA, we entered into a new EDA on October 31, 2025, under which we may offer and sell, from time to time, shares of our common stock having an aggregate sales price of up to $3.0 billion through an at-the-market offering program, which also includes an equity forward sales component and a collared forward sales component. We may offer and sell our common shares through the sales agents party to the EDA during the term of the agreement. The October 2025 EDA will terminate upon the earliest of (i) the sale of all common stock subject to the EDA, (ii) termination of the EDA pursuant to its terms, or (iii) October 31, 2028. Actual sales of common stock under the EDA will depend on a variety of factors, including market conditions, the trading price of our common stock, capital needs, and our determination of the appropriate sources of funding. As of December 31, 2025, we had not issued any shares of common stock under the October 2025 EDA.

In November 2025, we entered into a forward sales contract pursuant to our October 2025 EDA. Pursuant to the terms of the contract, 58,533 shares were sold with an initial forward price of $110.7748 per share. The initial forward price is subject to adjustment on a daily basis based on a floating interest rate factor and will decrease by other fixed amounts as specified in the contract. No amounts are recorded on our balance sheet with respect to this contract until actual settlement occurs. The contract requires us to, at our election on or before June 30, 2027, either (i) physically settle the transaction by issuing shares of our stock in exchange for net cash proceeds at the then-applicable forward sales price or (ii) net settle the transaction through the delivery or receipt of cash or shares in accordance with the contract provisions. As of December 31, 2025, no shares were settled under this contract. At December 31, 2025, we could have settled this forward sales contract with physical delivery of 58,533 shares of common stock to the counterparties in exchange for cash proceeds of $6.5 million. The forward sales contract could have alternatively been settled with delivery of approximately $0.3 million of cash or approximately 3,084 shares of common stock to us, if we had elected to net cash or net share settle, respectively, at December 31, 2025.

Any shares offered and sold under our EDAs were done pursuant to our registration statement on Form S-3 filed with the SEC on August 5, 2024 and the related prospectus supplements.

We had the following changes to our outstanding common stock during the years ended December 31, 2025 and 2024:

	2025	2024
Common stock shares outstanding at beginning of period	317,680,855	315,434,531
Shares issued:		
At-the-market offering program	**6,579,783**	1,030,674
Stock-based compensation	**609,995**	455,474
401(k)	**247,889**	336,800
Stock investment plan	**342,997**	423,376
Common stock shares outstanding at end of period	**325,461,519**	317,680,855

The following is a summary of shares purchased to fulfill exercised stock options and restricted stock awards during the years ended December 31:

(in millions, except share amounts)	2025	2024	2023
Shares purchased	**13,795**	23,292	182,795
Cost of shares purchased	**$ 1.3**	$ 3.2	$ 16.6

During the year ended December 31, 2025, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 16, 2025	March 1, 2025	$0.8925	First quarter
April 17, 2025	June 1, 2025	$0.8925	Second quarter
July 17, 2025	September 1, 2025	$0.8925	Third quarter
October 16, 2025	December 1, 2025	$0.8925	Fourth quarter

On January 22, 2026, our Board of Directors declared a quarterly cash dividend of $0.9525 per share, which equates to an annual dividend of $3.81 per share. The dividend is payable on March 1, 2026, to shareholders of record on February 13, 2026.

Earnings Per Share

The following table shows the computation of our basic and diluted EPS for the years ended December 31:

(in millions, except per share amounts)	2025	2024	2023
Numerator:			
Net income attributed to common shareholders	**$ 1,557.5**	$ 1,527.2	$ 1,331.7
Denominator:			
Weighted average basic shares outstanding	**321.9**	316.2	315.4
Dilutive effect of stock-based compensation awards	**0.6**	0.3	0.5
Dilutive effect of convertible senior notes	**1.3**	—	—
Weighted average diluted shares	**323.8**	316.5	315.9
Basic EPS	**$ 4.84**	$ 4.83	$ 4.22
Diluted EPS	**$ 4.81**	$ 4.83	$ 4.22

NOTE 12—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2025 and 2024:

(in millions, except share and per share amounts)	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WEC Energy Group				
$0.01 par value Preferred Stock	**15,000,000**	**—**	**—**	**$ —**
WE				
$100 par value, Six Per Cent. Preferred Stock	**45,000**	**44,498**	**—**	**4.4**
$100 par value, Serial Preferred Stock 3.60% Series	**2,286,500**	**260,000**	**$ 101**	**26.0**
$25 par value, Serial Preferred Stock	**5,000,000**	**—**	**—**	**—**
WPS				
$100 par value, Preferred Stock	**1,000,000**	**—**	**—**	**—**
PGL				
$100 par value, Cumulative Preferred Stock	**430,000**	**—**	**—**	**—**
NSG				
$100 par value, Cumulative Preferred Stock	**160,000**	**—**	**—**	**—**
Total				**$ 30.4**

NOTE 13—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates as of December 31:

(in millions, except percentages)	2025	2024
Commercial paper		
Amount outstanding at December 31	**$ 1,921.3**	$ 1,114.4
Average interest rate on amounts outstanding at December 31	**3.89 %**	4.63 %
Operating expense loans		
Amount outstanding at December 31 (1)	**$ 3.4**	$ 2.2

(1) Coyote Ridge, Tatanka Ridge, Samson I, and Jayhawk have entered into operating expense loans. In accordance with their limited liability company operating agreements, they received loans from the holders of their noncontrolling interests in proportion to their ownership interests.

Our average amount of commercial paper borrowings based on daily outstanding balances during 2025, was $1,124.2 million with a weighted-average interest rate during the period of 4.43%.

WEC Energy Group, WE, PGL, WPS, and WG have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require them to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 70.0%, 65.0%, 65.0%, 65.0%, and 65.0% or less, respectively. As of December 31, 2025, all companies were in compliance with their respective ratio.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing programs, including remaining available capacity under these facilities as of December 31:

(in millions)	Maturity	2025
Revolving credit facility (WEC Energy Group) (1) (2) (3)	August 2030	**$ 1,700.0**
Revolving credit facility (WE) (1) (2)	August 2030	**800.0**
Revolving credit facility (PGL) (1) (2)	August 2030	**600.0**
Revolving credit facility (WPS) (1) (2)	August 2030	**450.0**
Revolving credit facility (WG) (1) (4)	August 2030	**350.0**
Total short-term credit capacity		**$ 3,900.0**
Less:		
Letters of credit issued inside credit facilities		**$ 2.3**
Commercial paper outstanding		**1,921.3**
Available capacity under existing facilities		**$ 1,976.4**

(1) These revolving credit facilities have a renewal provision for two extensions, subject to lender approval. Each extension is for a period of one year.

(2) In August 2025, the capacity of the credit facilities for each of WEC Energy Group, WE, PGL, and WPS was increased to $1,700.0 million, $800.0 million, $600.0 million, and $450.0 million, respectively, and the maturity for each facility was extended to August 2030.

(3) In August 2025, WEC Energy Group terminated its $200.0 million bilateral credit facility.

(4) In August 2025, WG extended the maturity of its credit facility to August 2030.

The bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults, and change of control. In addition, pursuant to the terms of WEC Energy Group's credit agreement, we must ensure that certain of our subsidiaries comply with several of the covenants contained therein.

NOTE 14—LONG-TERM DEBT

The following table is a summary of our long-term debt outstanding as of December 31:

	2025			2024	
(in millions)	Maturity Date	Weighted Average Interest Rate	Balance	Weighted Average Interest Rate	Balance
WEC Energy Group Senior Notes (unsecured)	2026-2033	**3.96 %**	**$ 6,325.0**	4.13 %	$ 6,045.0
WEC Energy Group Junior Notes (unsecured) [1] [2]	2055-2056	**6.24 %**	**1,350.0**	6.72 %	750.0
WE Debentures (unsecured)	2028-2095	**4.55 %**	**4,485.0**	4.55 %	3,935.0
WEPCo Environmental Trust (secured, nonrecourse) [5] [10]	2026-2035	**1.58 %**	**78.8**	1.58 %	88.0
WPS Senior Notes (unsecured)	2028-2051	**3.99 %**	**1,975.0**	4.17 %	2,275.0
WG Debentures (unsecured)	2028-2046	**4.34 %**	**940.0**	3.92 %	840.0
PGL First and Refunding Mortgage Bonds (secured) [3]	2027-2047	**3.56 %**	**1,995.0**	3.56 %	1,995.0
NSG First Mortgage Bonds (secured) [4]	2027-2043	**3.81 %**	**177.0**	3.81 %	177.0
MERC Senior Notes (unsecured)	2027-2047	**3.64 %**	**210.0**	3.04 %	210.0
MGU Senior Notes (unsecured)	2027-2047	**4.38 %**	**190.0**	3.45 %	175.0
UMERC Senior Notes (unsecured)	2029-2035	**4.23 %**	**280.0**	3.26 %	160.0
Bluewater Gas Storage Senior Notes (unsecured) [5]	2026-2047	**4.07 %**	**128.0**	4.07 %	131.9
ATC Holding Senior Notes (unsecured)	2028-2030	**4.02 %**	**390.0**	4.05 %	475.0
We Power Subsidiaries Notes (secured, nonrecourse) [5] [6]	2026-2041	**5.71 %**	**769.9**	5.67 %	814.3
WECC Notes (unsecured)	2028	**6.94 %**	**50.0**	6.94 %	50.0
WECI Wind Holding I Senior Notes (secured, nonrecourse) [5] [7]	2026-2032	**2.75 %**	**202.1**	2.75 %	246.4
WECI Wind Holding II Senior Notes (secured, nonrecourse) [5] [8]	2026-2031	**6.38 %**	**147.9**	6.38 %	167.6
WECI Energy Holding III Senior Notes (secured, nonrecourse) [5] [9]	2026-2039	**5.73 %**	**446.2**	5.73 %	488.7
Total			**20,139.9**		19,023.9
Jayhawk acquisition			**7.5**		7.5
Unamortized debt issuance costs			**(110.4)**		(103.2)
Unamortized discount, net and other			**(19.5)**		(21.1)
Total long-term debt, including current portion			**20,017.5**		18,907.1
Current portion of long-term debt			**(1,519.4)**		(1,729.0)
Total long-term debt			**$ 18,498.1**		$ 17,178.1

(1) In November 2025, we issued our 2025 Junior Notes. Our 2025 Junior Notes are fixed-to-fixed reset rate junior subordinated notes. The rate for our 2025 Junior Notes was 5.625% as of December 31, 2025. The rate for our 2025 Junior Notes will reset on May 15, 2031; provided the reset rate will not be less than 5.625%.

(2) In December 2024, we issued our 2024A Junior Notes and 2024B Junior Notes. Our 2024A Junior Notes and 2024B Junior Notes are fixed-to-fixed reset rate junior subordinated notes. The rate for our 2024A Junior Notes was 6.69% as of December 31, 2025. The rate for our 2024A Junior Notes will reset on June 15, 2030. The rate for our 2024B Junior Notes was 6.74% as of December 31, 2025. The rate for our 2024B Junior Notes will reset on June 15, 2035.

(3) PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued $100 million of collateralized First Mortgage Bonds.

(4) NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

(5) The long-term debt of Bluewater, WECI Wind Holding I, WECI Wind Holding II, WECI Energy Holding III, WEPCo Environmental Trust, and We Power's subsidiaries requires periodic principal payments.

(6) We Power's subsidiaries' senior notes are secured by a collateral assignment of the leases between We Power's subsidiaries and WE related to PWGS and ERGS, as applicable.

[7] WECI Wind Holding I's Senior Notes are secured by a first priority security interest in the ownership interest of its subsidiaries, as well as a pledge of equity in WECI Wind Holding I.

[8] WECI Wind Holding II's Senior Notes are secured by a first priority security interest in the ownership interest of its subsidiaries, as well as a pledge of equity in WECI Wind Holding II.

[9] WECI Energy Holding III's Senior Notes are secured by a first priority security interest in the ownership interest of its subsidiaries, as well as a pledge of equity in WECI Energy Holding III.

[10] WEPCo Environmental Trust's ETBs are secured by a pledge of and lien on environmental control property, which includes the right to impose, collect and receive a non-bypassable environmental control charge paid by all of WE's retail electric distribution customers, the right to obtain true-up adjustments of the environmental control charges, and all revenues or other proceeds arising from those rights and interests. See Note 23, Variable Interest Entities, for more information.

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

In December 2024, the DOE issued to WE a conditional commitment for a federal loan guarantee for up to $2.5 billion of borrowings that would be used by WE to fund a portion of the costs to construct certain utility-scale renewable generation projects. The conditional commitment was issued pursuant to provisions of the IRA. Under the conditional commitment, the guaranteed borrowings would be senior, unsecured borrowings of WE made through the Federal Financing Bank and reduce WE's issuance of senior, unsecured obligations in the capital markets. Final approval and issuance of a loan guarantee by the DOE is subject to numerous conditions, including negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and the satisfaction of other conditions. While we continue to work with the DOE, there can be no assurance that the DOE will issue the loan guarantee for WE.

WEC Energy Group, Inc.

In June 2025, the remaining $120.0 million outstanding of our 3.55% Senior Notes, due June 15, 2025, matured, and principal and accrued interest were paid with proceeds received from issuing commercial paper.

In September 2025, our $500.0 million of 5.00% Senior Notes due September 27, 2025, matured, and principal and accrued interest were paid with proceeds received from issuing commercial paper.

In November 2025, we issued $600.0 million of 5.625% 2025 Junior Notes due May 15, 2056, and used the net proceeds to repay short-term debt and for other general corporate purposes.

In January 2026, our $1,000.0 million of 4.75% Senior Notes due January 9, 2026, matured, and principal and accrued interest were paid with proceeds received from issuing commercial paper.

Convertible Senior Notes

2028 Notes

In June 2025, we issued $900.0 million of 2028 Notes. The 2028 Notes are senior unsecured obligations and bear interest at an annual rate of 3.375%, payable semiannually beginning on December 1, 2025. Proceeds from the offering were used to repay short-term debt and for other general corporate purposes.

The 2028 Notes will mature on June 1, 2028, unless earlier converted or repurchased in accordance with their terms. No sinking fund is provided for the 2028 Notes. Upon the occurrence of a fundamental change, as defined in the related indenture, holders may require us to repurchase for cash all or any portion of their 2028 Notes. We may not redeem the 2028 Notes prior to their maturity date. Any fundamental change repurchases of the 2028 Notes will be at a price equal to 100% of the principal amount, plus accrued and unpaid interest.

Holders may convert all or any portion of their notes at their option at any time prior to the close of business on the business day immediately preceding March 1, 2028, only under the following circumstances:

- During any calendar quarter commencing after the calendar quarter ending on September 30, 2025, (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price of such series of notes on each applicable trading day;

- During the five consecutive business day period immediately after any ten consecutive trading day period (measurement period) in which the trading price per $1,000 principal amount of notes, as determined following a request by a holder or holders, for each trading day of the measurement period was less than 98% of the product of the last reported sale price of our common stock and the conversion rate of such series of notes on each such trading day; or

- Upon the occurrence of specified corporate events, as defined in the related indenture.

Holders may convert all or any portion of their notes at any time, regardless of the foregoing circumstances, on or after March 1, 2028, until the close of business on the second scheduled trading day immediately preceding the maturity date.

Upon conversion, we will pay cash up to the aggregate principal amount of the notes to be converted and pay or deliver cash, shares of our common stock, or a combination of cash and shares of our common stock, at our election, in respect of the remainder, if any, of our conversion obligation in excess of the aggregate principal amount of the notes being converted.

The initial conversion rate for the 2028 Notes is 7.7901 shares of common stock per $1,000 principal amount, which is equivalent to an initial conversion price of approximately $128.37 per share of our common stock. The conversion rate is subject to adjustment upon the occurrence of certain specified events, as defined in the related indenture, but will not be adjusted for any accrued and unpaid interest. In addition, upon the occurrence of a make-whole fundamental change, as defined in the related indenture, we will, in certain circumstances, increase the conversion rate by a number of additional shares of common stock for conversions in connection with the make-whole fundamental change.

2027 Notes and 2029 Notes

In the second quarter of 2024, we issued $862.5 million of 2027 Notes and $862.5 million of 2029 Notes. The 2027 Notes and 2029 Notes are senior unsecured obligations and bear interest at an annual rate of 4.375%, payable semiannually beginning on December 1, 2024. Proceeds from the offerings were used to repay short-term debt and for general corporate purposes.

The 2027 Notes will mature on June 1, 2027, and the 2029 Notes will mature on June 1, 2029, unless earlier converted or repurchased in accordance with their terms, or in the case of the 2029 Notes, redeemed by us. No sinking fund is provided for either series of the notes. Upon the occurrence of a fundamental change, as defined in the related indenture, holders may require us to repurchase for cash all or any portion of their 2027 or 2029 Notes. We may not redeem the 2027 Notes prior to their maturity date. We may redeem for cash all or part of the 2029 Notes, at our option, on or after June 1, 2027 and on or before the 41st scheduled trading day immediately preceding their maturity date, if the last reported sale price per share of our common stock has been at least 130% of the conversion price of the 2029 Notes then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period. Any redemptions or fundamental change repurchases of the 2027 Notes or 2029 Notes will be at a price equal to 100% of the principal amount, plus accrued and unpaid interest.

Holders may convert all or any portion of their notes at their option at any time prior to the close of business on the business day immediately preceding March 1, 2027, in the case of the 2027 Notes, and March 1, 2029, in the case of the 2029 Notes, only under the following circumstances:

- During any calendar quarter commencing after the calendar quarter ending on September 30, 2024 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price of such series of notes on each applicable trading day;

- During the five consecutive business day period immediately after any ten consecutive trading day period (measurement period) in which the trading price per $1,000 principal amount of notes of such series for each trading day of the measurement period was less than 98% of the product of the last reported sale price of our common stock and the conversion rate of such series of notes on each such trading day;

- Upon the occurrence of specified corporate events, as defined in the related indenture;
- In the case of the 2029 Notes only, if we call any of the 2029 Notes for redemption, at any time prior to the close of business on the second scheduled trading day prior to the redemption date, but only with respect to the 2029 Notes called (or deemed called) for redemption.

Holders may convert all or any portion of their notes at any time, regardless of the foregoing circumstances, on or after March 1, 2027, in the case of the 2027 Notes, or March 1, 2029, in the case of the 2029 Notes, until the close of business on the second scheduled trading day immediately preceding the maturity date of such series of notes.

Upon conversion, we will pay cash up to the aggregate principal amount of the notes to be converted and pay or deliver cash, shares of our common stock, or a combination of cash and shares of our common stock, at our election, in respect of the remainder, if any, of our conversion obligation in excess of the aggregate principal amount of the notes being converted.

The initial conversion rate for both the 2027 Notes and 2029 Notes is 10.1243 shares of common stock per $1,000 principal amount, which is equivalent to an initial conversion price of approximately $98.77 per share of our common stock. The conversion rate is subject to adjustment upon the occurrence of certain specified events, as defined in the related indenture, but will not be adjusted for accrued and unpaid interest. In addition, upon the occurrence of a make-whole fundamental change, as defined in the related indenture, we will, in certain circumstances, increase the conversion rate by a number of additional shares of common stock for conversions in connection with the make-whole fundamental change.

As of December 31, 2025, the conditions allowing holders to convert their notes were not met. In accordance with the guidance in ASC Subtopic 470-20, Debt – Debt with Conversion and Other Options, the 2027 Notes, 2028 Notes, and 2029 Notes were accounted for in their entirety as a liability on our balance sheet. The following is a summary of our convertible debt instruments as of December 31, 2025:

(in millions)	**Principal Amount**	**Unamortized Debt Issuance Costs**	**Net Carrying Amount**	**Fair Value Amount** [(1)]
2027 Notes	**$ 862.5**	**$ (4.7)**	**$ 857.8**	**$ 977.8**
2028 Notes	**900.0**	**(8.5)**	**891.5**	**912.6**
2029 Notes	**862.5**	**(6.8)**	**855.7**	**1,011.7**

[(1)] The fair values are categorized in Level 2 of the fair value hierarchy. See Note 1(r), Fair Value Measurements, for more information on the levels of the fair value hierarchy.

The following table provides a summary of the interest expense recorded for each of the 2027 Notes, 2028 Notes, and 2029 Notes for the year ended December 31:

(in millions)	**2025**	**2024**
2027 Notes		
Contractual interest expense	**$ 37.7**	$ 22.3
Amortization of debt issuance costs	**3.3**	1.9
Total interest expense – 2027 Notes	**41.0**	24.2
2028 Notes		
Contractual interest expense	**$ 17.0**	$ —
Amortization of debt issuance costs	**1.8**	—
Total interest expense – 2028 Notes	**18.8**	—
2029 Notes		
Contractual interest expense	**37.7**	22.3
Amortization of debt issuance costs	**2.0**	1.2
Total interest expense – 2029 Notes	**$ 39.7**	$ 23.5

Wisconsin Electric Power Company

In June 2025, WE's $250.0 million of 3.10% Debentures, due June 1, 2025, matured, and outstanding principal and accrued interest were paid with proceeds received from issuing commercial paper.

In September 2025, WE issued $500.0 million of 4.15% Debentures, due October 15, 2030, and used the net proceeds to repay short-term debt and for other general corporate purposes.

In December 2025, WE issued $300.0 million of 3.95% Debentures, due March 1, 2029, and used the net proceeds to repay short-term debt and for other general corporate purposes.

Wisconsin Public Service Corporation

In November 2025, WPS's $300.0 million of 5.35% Senior Notes, due November 10, 2025, matured, and outstanding principal and accrued interest were paid with proceeds received from issuing commercial paper.

In January 2026, WPS issued $300.0 million of 4.25% Senior Notes, due January 15, 2031, and used the net proceeds to repay short-term debt and for other general corporate purposes.

Wisconsin Gas LLC

In September 2025, WG issued $175.0 million of 4.70% Debentures, due October 1, 2030, and $125.0 million of 5.39% Debentures, due October 1, 2035, and used the net proceeds to repay $200.0 million of WG's 3.53% Debentures that matured on September 30, 2025, and to repay short-term debt and for other general limited liability company purposes.

Minnesota Energy Resources Corporation

In April 2025, MERC issued $50.0 million of 5.20% Senior Notes, due May 1, 2030, and used the net proceeds to repay MERC's $50.0 million of 2.69% Senior Notes that matured on May 1, 2025.

Michigan Gas Utilities Corporation

In April 2025, MGU issued $75.0 million of 5.20% Senior Notes, due May 1, 2030, and used the net proceeds to repay MGU's $60.0 million of 2.69% Senior Notes that matured on May 1, 2025 and intercompany short-term debt to its parent, Integrys.

Upper Michigan Energy Resources Corporation

In August 2025, UMERC issued $80.0 million of 5.31% Senior Notes, due August 14, 2030, and $40.0 million of 5.93% Senior Notes, due August 14, 2035, and used the net proceeds to repay intercompany short-term debt to its parent, WEC Energy Group, and for other general corporate purposes.

ATC Holding LLC

In December 2025, ATC's $85.0 million of 4.18% Debentures, due December 20, 2025, matured, and outstanding principal and accrued interest were paid with a contribution received from WEC Energy Group.

Maturities of Long-Term Debt Outstanding

The following table shows the long-term debt securities maturing within one year of December 31, 2025:

(in millions)	Interest Rate	Maturity Date [1]	Principal Amount
WEC Energy Group Senior Notes (unsecured)	4.75%	January	$ 1,000.0
WEC Energy Group Senior Notes (unsecured)	5.60%	September	350.0
WEPCo Environmental Trust (secured, nonrecourse)	1.58%	Semi-annually	9.3
Bluewater Gas Storage Senior Notes (unsecured)	3.76%	Semi-annually	3.1
Bluewater Gas Storage Senior Notes (unsecured)	5.41%	Semi-annually	1.0
We Power Subsidiaries Notes – PWGS (secured, nonrecourse)	4.91%	Monthly	8.9
We Power Subsidiaries Notes – ERGS (secured, nonrecourse)	5.209%	Semi-annually	17.1
We Power Subsidiaries Notes – ERGS (secured, nonrecourse)	4.673%	Semi-annually	12.8
We Power Subsidiaries Notes – PWGS (secured, nonrecourse)	6.00%	Monthly	7.9
WECI Wind Holding I Senior Notes (secured, nonrecourse)	2.75%	Semi-annually	45.1
WECI Wind Holding II Senior Notes (secured, nonrecourse)	6.38%	Semi-annually	22.6
WECI Energy Holding III Senior Notes (secured, nonrecourse)	5.73%	Semi-annually	41.6
Total			$ 1,519.4

[1] Maturity dates listed as semi-annually and monthly are associated with debt that requires periodic principal payments.

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2025:

(in millions)	Payments
2026	$ 1,519.4
2027	2,137.3
2028	3,203.2
2029	2,943.4
2030	1,691.9
Thereafter	8,644.7
Total	$ 20,139.9

Certain long-term debt obligations contain financial and other covenants related to payment of principal and interest when due, maintaining certain total funded debt to capitalization ratios, and various other obligations. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

NOTE 15—LEASES

In accordance with ASC Subtopic 980-842, Regulated Operations – Leases (Subtopic 980-842), the timing of expense recognition associated with our leases is modified to conform to the rate treatment. The difference between the lease expense that is allowed for rate-making purposes and the unadjusted lease expense calculated under Topic 842 is deferred as a regulatory asset on our balance sheets. For our finance leases, amortization of the right-of-use asset is modified so that the total of the imputed interest and amortization costs equals the lease expense that is allowed for rate-making purposes in accordance with Subtopic 980-842.

Obligations Under Operating Leases

We have recorded right of use assets and lease liabilities primarily associated with the following operating leases:

- Leases of office space, primarily related to several floors we are leasing in the Aon Center office building in Chicago, Illinois, through April 2039.
- Land we are leasing related to our Rothschild biomass plant through June 2051.
- Rail cars we are leasing to transport coal to various generating facilities through June 2027.
- Land we are leasing related to our utility and non-utility solar generation projects through May 2075.

The operating leases generally require us to pay property taxes, insurance premiums, and operating and maintenance costs associated with the leased property. Certain of our leases contain options for early termination or to renew past the initial term, as set forth in the lease agreements. These options are included in our calculation of the lease obligations if it is reasonably certain that they will be exercised.

Obligations Under Finance Leases

Land Leases – Utility Solar Generation

We have various land leases related to our investments in utility solar generation. Each lease has an initial term and one or more optional extensions. We expect the optional extensions to be exercised, and, as a result, all of the land leases are being amortized over an extended term which can range from 40 to 50 years. Once a solar project achieves commercial operation, the lease liability is remeasured to reflect the final total acres being leased. Our payments related to these leases are being recovered through rates.

Land Leases – Non-Utility Energy Infrastructure Solar Generation

We have various land leases related to our investments in non-utility solar generation. Each lease has an initial term and one or more optional extensions. We expect the optional extensions to be exercised, and, as a result, all of the land leases are being amortized over an extended term of approximately 50 years.

Amounts Recognized in the Financial Statements and Other Information

The components of lease expense and supplemental cash flow information related to our leases for the years ended December 31 are as follows:

(in millions)	2025	2024	2023
Finance lease expense			
Amortization of right of use assets [1]	**$ 1.1**	$ 0.2	$ —
Interest on lease liabilities [2]	**6.9**	1.8	0.8
Operating lease expense [3]	**7.8**	5.2	4.7
Short-term lease expense [3]	**0.2**	0.6	1.2
Total lease expense	**$ 16.0**	$ 7.8	$ 6.7
Other information			
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from finance leases	**$ 6.4**	$ 1.8	$ 0.8
Operating cash flows from operating leases	**7.5**	7.1	6.8
Financing cash flows from finance leases	**0.9**	—	—
Non-cash activities			
Right of use assets obtained in exchange for finance lease liabilities [4]	**$ 63.8**	$ 153.2	$ 32.8
Right of use assets obtained in exchange for operating lease liabilities	**43.5**	2.6	18.3
Weighted-average remaining lease term – finance leases	**49.6 years**	50.2 years	49.4 years
Weighted-average remaining lease term – operating leases	**35.8 years**	25.1 years	22.4 years
Weighted-average discount rate – finance lease [5]	**6.0 %**	5.9 %	5.3 %
Weighted average discount rate – operating leases [5]	**6.3 %**	5.9 %	5.8 %

(1) Amortization of right of use assets was included as a component of depreciation and amortization expense.

(2) Interest on lease liabilities was included as a component of interest expense.

(3) Operating and short-term lease expense were included as a component of other operation and maintenance expense.

(4) Amounts are net of any reductions to right of use assets and finance lease liabilities resulting from remeasurements.

(5) Because our leases do not provide an implicit rate of return, we used an estimate of the fully collateralized incremental borrowing rates based upon information available for similarly rated companies in determining the present value of lease payments.

The following table summarizes our finance and operating lease right of use assets and obligations at December 31:

(in millions)	2025	2024	Balance Sheet Location
Right of use assets			
Operating lease right of use assets, net	**$ 69.5**	$ 32.1	Other long-term assets
Finance lease right of use assets, net			
Land leases – utility solar generation	**$ 291.5**	$ 235.8	
Land leases –non-utility energy infrastructure solar generation	**42.3**	43.5	
Other	**1.7**	2.0	
Total finance lease right of use assets, net [1]	**$ 335.5**	$ 281.3	Property, plant, and equipment, net
Lease obligations			
Current operating lease liabilities	**$ 3.1**	$ 4.3	Other current liabilities
Long-term operating lease liabilities	**$ 73.0**	$ 37.5	Other long-term liabilities
Current finance lease liabilities			
Other	**$ 0.2**	$ 0.2	Other current liabilities
Long-term finance lease liabilities			
Land leases – utility solar generation	**$ 327.3**	$ 257.9	
Land leases –non-utility energy infrastructure solar generation	**43.3**	43.8	
Other	**1.4**	1.6	
Total long-term finance lease liabilities	**$ 372.0**	$ 303.3	Finance lease obligations

[1] Amounts are net of accumulated amortization of $16.3 million and $10.0 million at December 31, 2025 and 2024, respectively.

Future minimum lease payments under our operating and finance leases and the present value of our net minimum lease payments as of December 31, 2025, were as follows:

(in millions)	Total Operating Leases	Land Leases - Utility Solar Generation	Land Leases - Non-Utility Energy Infrastructure Solar Generation	Other	Total Finance Leases
2026	$ 7.0	$ 9.5	$ 2.2	$ 0.3	$ 12.0
2027	6.3	13.8	2.3	0.3	16.4
2028	5.2	15.9	2.3	0.1	18.3
2029	5.2	16.2	2.3	0.1	18.6
2030	5.0	16.6	2.4	0.1	19.1
Thereafter	208.2	1,221.0	156.6	2.5	1,380.1
Total minimum lease payments	236.9	1,293.0	168.1	3.4	1,464.5
Less: Interest	(160.8)	(965.7)	(124.8)	(1.8)	(1,092.3)
Present value of minimum lease payments	76.1	327.3	43.3	1.6	372.2
Less: Short-term lease liabilities	(3.1)	—	—	(0.2)	(0.2)
Long-term lease liabilities	$ 73.0	$ 327.3	$ 43.3	$ 1.4	$ 372.0

As of February 20, 2026, we have not entered into any material leases that have not yet commenced.

NOTE 16—INCOME TAXES

We adopted the new disclosure provisions of ASU No. 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures, effective January 1, 2025. See Note 1(q), Income Taxes, for more information on the adoption of this ASU.

Income Tax Expense

The following table is a summary of the components of income tax expense for the years ended December 31:

(in millions)	2025	2024	2023
Current tax expense (benefit)			
Federal	**$ (242.5)**	$ (178.5)	$ (36.7)
State	**(8.0)**	(128.5)	21.9
Deferred tax expense, net			
Federal	**240.9**	386.2	130.1
State	**135.6**	152.5	99.8
ITCs, net	**(8.0)**	(9.7)	(10.5)
Total income tax expense	**$ 118.0**	$ 222.0	$ 204.6

Statutory Rate Reconciliation

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable United States statutory federal income tax rate to income before income taxes as a result of the following:

	2025		2024		2023	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Income before income taxes	**$ 1,673.5**		$ 1,746.3		$ 1,536.3	
US federal statutory income tax rate	**$ 351.9**	**21.0 %**	$ 367.3	21.0 %	$ 322.6	21.0 %
State and local income taxes net of federal tax effect [(1)]	**101.2**	**6.0 %**	108.0	6.2 %	94.3	6.1 %
Tax credits						
PTCs, net [(2)]	**(261.3)**	**(15.6)%**	(200.1)	(11.5)%	(168.2)	(10.9)%
Other	**(8.2)**	**(0.5)%**	(10.0)	(0.6)%	(10.9)	(0.7)%
Nontaxable or nondeductible items						
AFUDC-Equity [(3)]	**(21.0)**	**(1.3)%**	(12.6)	(0.7)%	(12.4)	(0.8)%
Other	**11.0**	**0.7 %**	4.0	0.2 %	4.4	0.2 %
Changes in unrecognized tax benefits	**(2.0)**	**(0.1)%**	(0.4)	— %	(1.8)	(0.1)%
Other adjustments						
Federal excess deferred tax amortization [(4)]	**(43.0)**	**(2.6)%**	(36.7)	(2.1)%	(37.6)	(2.4)%
Other, net	**(10.6)**	**(0.5)%**	2.5	0.2 %	14.2	0.9 %
Total income tax expense	**$ 118.0**	**7.1 %**	$ 222.0	12.7 %	$ 204.6	13.3 %

(1) State taxes in Wisconsin made up the majority of the tax effect in this category.

(2) PTCs are an inflation adjusted US federal income tax credit for each kilowatt hour of electricity generated by certain renewable energy projects.

(3) AFUDC-Equity represents the cost of capital (i.e. ROE) that is added to the construction cost of an asset while it is being built. The tax benefit for regulated utilities from AFUDC-Equity is a regulatory gross-up to allow the recovery of income taxes on the equity portion of construction costs, even though it is not a tax deductible expense.

(4) The Tax Legislation required our regulated utilities to remeasure their deferred income taxes and we began to amortize the resulting excess deferred income taxes beginning in 2018, in accordance with normalization requirements. The decrease in income tax expense related to the amortization of the deferred tax benefits is offset by a decrease in revenue as the benefits are returned to customers, resulting in no impact on net income.

Deferred Income Tax Assets and Liabilities

The components of deferred income taxes as of December 31 were as follows:

(in millions)	2025	2024
Deferred tax assets		
Tax gross up – regulatory items	**$ 416.9**	$ 420.1
Future tax benefits	**240.9**	165.4
Deferred revenues	**76.8**	76.0
Other	**206.1**	167.9
Total deferred tax assets	**940.7**	829.4
Valuation allowance	**(1.1)**	(1.1)
Net deferred tax assets	**$ 939.6**	$ 828.3
Deferred tax liabilities		
Property-related	**$ 5,041.5**	$ 4,545.2
Investment in affiliates	**1,143.6**	1,103.9
Employee benefits and compensation	**229.2**	231.4
Deferred costs – plant retirements	**178.0**	194.3
Other	**239.0**	268.2
Total deferred tax liabilities	**6,831.3**	6,343.0
Deferred tax liability, net	**$ 5,891.7**	$ 5,514.7

Consistent with ratemaking treatment, deferred taxes related to our regulated utilities in the table above are offset for temporary differences that have related regulatory assets and liabilities.

The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2025 and 2024 are summarized in the tables below:

2025 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2025				
Federal tax credit	**$ —**	**$ 206.5**	**$ —**	**2042**
State net operating loss	**685.6**	**34.1**	**(1.1)**	**2032**
Other state benefits	**—**	**0.3**	**—**	**2029**
Balance as of December 31, 2025	**$ 685.6**	**$ 240.9**	**$ (1.1)**	

2024 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2024				
Federal tax credit	$ —	$ 157.9	$ —	2042
State net operating loss	107.5	7.2	(1.1)	2032
Other state benefits	—	0.3	—	2028
Balance as of December 31, 2024	$ 107.5	$ 165.4	$ (1.1)	

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in millions)	2025	2024	2023
Balance as of January 1	**$ 4.4**	$ 4.6	$ 6.3
Additions for tax positions of prior years	**0.1**	—	0.2
Reductions for tax positions of prior years	**(1.5)**	(0.2)	(1.9)
Balance as of December 31	**$ 3.0**	$ 4.4	$ 4.6

The amount of unrecognized tax benefits as of December 31, 2025 and 2024, excludes deferred tax assets related to uncertainty in income taxes of $0.7 million and $1.0 million, respectively. As of December 31, 2025 and 2024, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $2.3 million and $3.4 million, respectively.

Interest accrued related to unrecognized tax benefits is as follows:

(in millions)	2025	2024	2023
Balance as of January 1	**$ 0.9**	$ 0.6	$ 0.5
Interest expense (income) related to unrecognized tax benefits	**(0.6)**	0.3	0.1
Balance as of December 31	**$ 0.3**	$ 0.9	$ 0.6

For the years ended December 31, 2025, 2024, and 2023, we recognized no penalties related to unrecognized tax benefits in our consolidated income statements. At December 31, 2025 and 2024, we had no amounts accrued for penalties related to unrecognized tax benefits.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2025, with a few exceptions, we were subject to examination by federal and state or local tax authorities for the 2021 through 2025 tax years in our major operating jurisdictions as follows:

Jurisdiction	Years
Federal	2022–2025
Illinois	2021–2025
Michigan	2021–2025
Minnesota	2021–2025
Wisconsin	2021–2025

Cash Received For Income Taxes, Net

The table below is a summary of income taxes paid (received) by jurisdiction for the years ended December 31:

(in millions)	2025	2024	2023
Federal	**$ (256.3)** [1]	$ (265.0) [2]	$ (75.0) [3]
State	**(25.0)**	0.8	16.1
Total income taxes received, net	**$ (281.3)**	$ (264.2)	$ (58.9)

[1] Includes $256.3 million related to 2025 and 2024 PTCs that were sold to third parties.

[2] Includes $269.1 million related to 2024 and 2023 PTCs that were sold to third parties.

[3] Includes $75.0 million related to 2023 PTCs that were sold to third parties.

Income taxes received or paid (net of refunds) exceeded 5 percent of total income taxes received or paid (net of refunds) in the following jurisdiction:

(in millions)	2025	2024	2023
Wisconsin	**$ (25.0)**	$ — [1]	$ 12.0

[1] Jurisdiction below the threshold for the period presented.

NOTE 17—FAIR VALUE MEASUREMENTS

The following tables summarize our financial assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	December 31, 2025			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	**$ 1.5**	**$ 18.3**	**$ —**	**$ 19.8**
FTRs and TCRs	**—**	**—**	**6.5**	**6.5**
Total derivative assets	**$ 1.5**	**$ 18.3**	**$ 6.5**	**$ 26.3**
Investments held in rabbi trust	**$ 42.0**	**$ —**	**$ —**	**$ 42.0**
Derivative liabilities				
Natural gas contracts	**$ 23.3**	**$ 8.4**	**$ —**	**$ 31.7**
FTRs and TCRs	**—**	**—**	**0.8**	**0.8**
Total derivative liabilities	**$ 23.3**	**$ 8.4**	**$ 0.8**	**$ 32.5**

	December 31, 2024			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 19.6	$ 13.7	$ —	$ 33.3
FTRs and TCRs	—	—	7.8	7.8
Total derivative assets	$ 19.6	$ 13.7	$ 7.8	$ 41.1
Investments held in rabbi trust	$ 52.1	$ —	$ —	$ 52.1
Derivative liabilities				
Natural gas contracts	$ 7.1	$ 6.8	$ —	$ 13.9

The derivative assets and liabilities listed in the tables above include options, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs and TCRs, which are used at our electric utilities and certain of our non-utility wind parks to manage electric transmission congestion costs in the MISO Energy Markets and the Southwest Power Pool, Inc. Integrated Marketplace, respectively.

We hold investments in the Integrys rabbi trust. These investments are used to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans. These investments are included in other long-term assets on our balance sheets. During the years ended December 31, 2025, 2024, and 2023, the net unrealized gains included in earnings related to the investments held at the end of the period were $5.8 million, $9.0 million, and $10.0 million, respectively.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy at December 31:

(in millions)	2025	2024	2023
Balance at the beginning of the period	**$ 7.8**	$ 7.2	$ 7.8
Purchases	**23.7**	28.7	21.0
Net realized and unrealized losses included in earnings (1)	**—**	(0.7)	(0.5)
Sales	**(1.0)**	—	—
Settlements	**(24.8)**	(27.4)	(21.1)
Balance at the end of the period	**$ 5.7**	$ 7.8	$ 7.2
Net unrealized gains included in earnings attributable to Level 3 derivatives held at the end of the reporting period (1)	**$ 0.1**	$ —	$ 0.5

(1) Amounts relate to FTRs and TCRs included in our non-utility energy infrastructure segment. These net realized and unrealized gains and losses are recorded in operating revenues on our income statements.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value at December 31:

	2025		2024	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock of subsidiary	**$ 30.4**	**$ 21.2**	$ 30.4	$ 21.2
Long-term debt, including current portion	**20,017.5**	**19,609.1**	18,907.1	17,840.8

The fair values of our long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

NOTE 18—DERIVATIVE INSTRUMENTS

Derivative assets and liabilities are included in the other current and other long-term line items on our balance sheets. The following table shows our derivative assets and derivative liabilities. None of the derivatives shown below were designated as hedging instruments.

	December 31, 2025		December 31, 2024	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Current				
Natural gas contracts	**$ 19.7**	**$ 30.0**	$ 29.2	$ 13.9
FTRs and TCRs	**6.5**	**0.8**	7.8	—
Total current	**26.2**	**30.8**	37.0	13.9
Long-term				
Natural gas contracts	**0.1**	**1.7**	4.1	—
Total	**$ 26.3**	**$ 32.5**	$ 41.1	$ 13.9

Realized gains and losses on derivatives used in our regulated utility operations are recorded in cost of sales upon settlement; however, they may be subsequently deferred for future rate recovery or refund as the gains and losses are included in our utilities' fuel and natural gas cost recovery mechanisms. Realized gains and losses on FTRs and TCRs used in our non-utility operations are recorded in operating revenues on the income statements. Our realized gains and losses and the estimated notional volumes related to these settlements were as follows for the years ended:

	December 31, 2025		December 31, 2024		December 31, 2023	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains (Losses)	Volumes	Gains (Losses)
Natural gas contracts	**202.4 Dth**	**$ (19.2)**	206.3 Dth	$ (127.8)	198.0 Dth	$ (259.1)
FTRs and TCRs						
Regulated utility operations	**26.3 MWh**	**18.9**	28.4 MWh	8.3	29.3 MWh	27.4
Non-utility operations	**0.7 MWh**	**(0.1)**	1.3 MWh	(0.1)	0.9 MWh	(1.5)
Total		**$ (0.4)**		$ (119.6)		$ (233.2)

At December 31, 2025 and 2024, we had posted cash collateral of $41.4 million and $16.0 million, respectively. We had also received cash collateral of $4.2 million at December 31, 2024.

The following table shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on our balance sheets:

	December 31, 2025		December 31, 2024	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 26.3**	**$ 32.5**	$ 41.1	$ 13.9
Gross amount not offset on the balance sheet	**(2.0)**	**(23.8)** [1]	(11.5) [2]	(7.3)
Net amount	**$ 24.3**	**$ 8.7**	$ 29.6	$ 6.6

(1) Includes cash collateral posted of $21.8 million.

(2) Includes cash collateral received of $4.2 million.

Cash Flow Hedges

We previously entered into forward interest rate swap agreements to mitigate the interest rate exposure associated with the issuance of long-term debt related to the acquisition of Integrys. These swap agreements were settled in 2015, and we continue to amortize amounts out of accumulated other comprehensive loss into interest expense over the periods in which the interest costs are recognized in earnings. The derivative gains related to these swap agreements reclassified from accumulated other comprehensive loss to interest expense during the years ended December 31, 2025, 2024, and 2023 were not significant. At December 31, 2025, the amount expected to be reclassified from accumulated other comprehensive loss to interest expense over the next twelve months was also not significant.

NOTE 19—GUARANTEES

The following table shows our outstanding guarantees:

		Expiration		
(in millions)	Total Amounts Committed at December 31, 2025	Less Than 1 Year	1 to 3 Years	Over 3 Years
Standby letters of credit [1]	**$ 188.2**	$ 30.7	$ 30.2	$ 127.3
Surety bonds [2]	**46.5**	46.4	0.1	—
Other guarantees [3]	**9.6**	—	—	9.6
Total guarantees	**$ 244.3**	$ 77.1	$ 30.3	$ 136.9

(1) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(2) Primarily for environmental remediation, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(3) Related to workers compensation coverage for which a liability was recorded on our balance sheets.

NOTE 20—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We and our subsidiaries have defined benefit pension plans that cover substantially all of our employees, as well as several unfunded non-qualified retirement plans. In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

Generally, other than those employees who receive a contribution to their 401(k) savings plan as described below, former Wisconsin Energy Corporation employees receive a benefit based on a percentage of their annual salary plus an interest credit. Wisconsin Energy Corporation management employees hired after December 31, 2014, and certain new represented employees hired after May 1, 2017, receive an annual company contribution to their 401(k) savings plan instead of being enrolled in the defined benefit plans.

For former Integrys employees, the defined benefit pension plans are closed to all new hires. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013. These employees receive an annual company contribution to their 401(k) savings plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets:

	Pension Benefits		**OPEB Benefits**	
(in millions)	**2025**	**2024**	**2025**	**2024**
Change in benefit obligation				
Obligation at January 1	**$ 2,209.2**	$ 2,352.4	**$ 460.9**	$ 448.1
Service cost	**20.8**	24.2	**11.3**	10.9
Interest cost	**118.6**	116.6	**25.7**	22.7
Participant contributions	**—**	—	**11.5**	11.2
Plan amendments	**—**	—	**(0.4)**	—
Actuarial (gain) loss	**8.2**	(99.6)	**28.3**	6.9
Benefit payments	**(193.7)**	(184.4)	**(46.8)**	(41.7)
Federal subsidy on benefits paid	**N/A**	N/A	**1.4**	1.4
Transfer	**—**	—	**1.5**	1.4
Obligation at December 31	**$ 2,163.1**	$ 2,209.2	**$ 493.4**	$ 460.9
Change in fair value of plan assets				
Fair value at January 1	**$ 2,624.3**	$ 2,665.8	**$ 850.0**	$ 829.6
Actual return on plan assets	**221.6**	129.8	**87.9**	49.5
Employer contributions net of plan transfer	**11.8**	13.1	**1.9**	1.4
Participant contributions	**—**	—	**11.5**	11.2
Benefit payments	**(193.7)**	(184.4)	**(46.8)**	(41.7)
Fair value at December 31	**$ 2,664.0**	$ 2,624.3	**$ 904.5**	$ 850.0
Funded status at December 31	**$ 500.9**	$ 415.1	**$ 411.1**	$ 389.1

In 2025, we had actuarial losses related to our pension benefit obligations of $8.2 million and actuarial gains in 2024 of $99.6 million. The primary driver for the actuarial loss was the decrease in discount rate. The primary driver for the actuarial gain was a higher discount rate in 2024. Partially offsetting the gain in 2024, was lower than expected asset returns. The discount rate for our pension benefits was 5.50%, 5.69%, and 5.19% in 2025, 2024, and 2023, respectively.

In 2025 and 2024, we had actuarial losses related to our OPEB benefit obligation of $28.3 million and $6.9 million, respectively, both of which were driven by changes to medical trend assumptions and claims and premium updates. The 2025 loss was also driven by a lower discount rate. Partially offsetting the loss in 2024, was a higher discount rate. The discount rate for our OPEB benefits was 5.54%, 5.71%, and 5.16% in 2025, 2024, and 2023, respectively.

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Benefits		**OPEB Benefits**	
(in millions)	**2025**	**2024**	**2025**	**2024**
Pension and OPEB assets	**$ 646.3**	$ 562.4	**$ 436.1**	$ 406.1
Other long-term liabilities	**145.4**	147.3	**25.0**	17.0
Total net assets	**$ 500.9**	$ 415.1	**$ 411.1**	$ 389.1

The accumulated benefit obligation for all defined benefit pension plans was $2,112.5 million and $2,156.8 million as of December 31, 2025 and 2024, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2025	2024
Accumulated benefit obligation	**$ 283.0**	$ 286.0
Fair value of plan assets	**141.7**	143.2

The following table shows information for pension plans with a projected benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2025	2024
Projected benefit obligation	**$ 287.1**	$ 290.5
Fair value of plan assets	**141.7**	143.2

The following table shows information for OPEB plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2025	2024
Accumulated benefit obligation	**$ 205.5**	$ 194.0
Fair value of plan assets	**180.5**	177.0

The following table shows the amounts that had not yet been recognized in our net periodic benefit cost (credit) as of December 31:

	Pension Benefits		OPEB Benefits	
(in millions)	2025	2024	2025	2024
Pre-tax accumulated other comprehensive income (loss) [1]				
Net actuarial loss (gain)	**$ 11.6**	$ 12.3	**$ (1.0)**	$ (1.1)
Net regulatory assets (liabilities) [2]				
Net actuarial loss (gain)	**$ 501.1**	$ 578.7	**$ (146.1)**	$ (148.8)
Prior service credits	**(2.0)**	(2.1)	**(8.4)**	(15.8)
Total	**$ 499.1**	$ 576.6	**$ (154.5)**	$ (164.6)

[1] Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

[2] Amounts related to the utilities and WBS are recorded as net regulatory assets or liabilities.

The components of net periodic benefit cost (credit) (including amounts capitalized to our balance sheets) for the years ended December 31 were as follows:

	Pension Benefits			OPEB Benefits		
(in millions)	2025	2024	2023	2025	2024	2023
Service cost	**$ 20.8**	$ 24.2	$ 24.0	**$ 11.3**	$ 10.9	$ 9.8
Interest cost	**118.6**	116.6	122.3	**25.7**	22.7	21.6
Expected return on plan assets	**(175.1)**	(182.1)	(187.4)	**(54.3)**	(52.7)	(53.0)
Plan settlement	**(1.2)**	4.0	1.3	**—**	—	—
Amortization of prior service cost (credit)	**(0.1)**	(0.1)	—	**(7.8)**	(13.5)	(14.8)
Amortization of net actuarial loss (gain)	**41.1**	59.5	33.0	**(8.2)**	(7.6)	(12.3)
Net periodic benefit cost (credit)	**$ 4.1**	$ 22.1	$ (6.8)	**$ (33.3)**	$ (40.2)	$ (48.7)

Effective January 1, 2023, the PSCW approved escrow accounting for pension and OPEB costs. As a result, as of December 31, 2025 and 2024, our balance sheet included a $14.7 million regulatory liability and a $24.9 million regulatory asset for pension costs, respectively, and a $0.7 million and a $38.2 million regulatory asset for OPEB costs, respectively.

The weighted-average assumptions used to determine the benefit obligations for the plans were as follows for the years ended December 31:

	Pension Benefits		OPEB Benefits	
	2025	**2024**	**2025**	**2024**
Discount rate	**5.50%**	5.69%	**5.54%**	5.71%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Interest credit rate	**4.83%**	4.85%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**8.00%**	7.00%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2032**	2033
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**9.92%**	6.10%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2034**	2030

The weighted-average assumptions used to determine the net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Benefits		
	2025	**2024**	**2023**
Discount rate	**5.69%**	5.18%	5.49%
Expected return on plan assets	**6.61%**	6.61%	6.62%
Rate of compensation increase	**4.00%**	4.00%	4.00%
Interest credit rate	**4.85%**	4.84%	4.62%

	OPEB Benefits		
	2025	**2024**	**2023**
Discount rate	**5.71%**	5.16%	5.50%
Expected return on plan assets	**6.50%**	6.50%	6.50%
Assumed medical cost trend rate (Pre 65)	**7.00%**	6.25%	6.50%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2033**	2031	2031
Assumed medical cost trend rate (Post 65)	**6.10%**	6.39%	6.00%
Ultimate trend rate (Post 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Post 65)	**2030**	2030	2031

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the trust. For 2026, the expected return on assets assumption is 6.61% for the pension plans and 6.50% for the OPEB plans.

Plan Assets

Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

The target asset allocations are 25% equity investments, 55% fixed income investments, and 20% private equity and real estate investments for both the legacy Wisconsin Energy Corporation and legacy Integrys pension trusts. The legacy Wisconsin Energy Corporation OPEB trust target asset allocations are 45% equity investments, 45% fixed income investments, and 10% real estate investments. The two largest legacy OPEB trusts for Integrys have the same target asset allocations of 45% equity investments, 45% fixed income investments, and 10% real estate investments. Equity securities include investments in large-cap, mid-cap, and small-cap companies. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

Pension and OPEB plan investments are recorded at fair value. See Note 1(r), Fair Value Measurements, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

The following tables provide the fair values of our investments by asset class:

	December 31, 2025							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Equity securities:								
United States equity	**$ 160.8**	**$ —**	**$ —**	**$ 160.8**	**$ 97.3**	**$ —**	**$ —**	**$ 97.3**
International equity	**173.7**	**—**	**—**	**173.7**	**100.8**	**—**	**—**	**100.8**
Fixed income securities: [1]								
United States bonds	**—**	**933.5**	**1.4**	**934.9**	**110.6**	**219.3**	**0.1**	**330.0**
International bonds	**—**	**63.5**	**—**	**63.5**	**—**	**7.7**	**—**	**7.7**
	$ 334.5	**$ 997.0**	**$ 1.4**	**$ 1,332.9**	**$ 308.7**	**$ 227.0**	**$ 0.1**	**$ 535.8**
Investments measured at net asset value:								
Equity securities				**412.6**				**206.0**
Fixed income securities				**127.6**				**55.3**
Other				**790.9**				**107.4**
Total				**$ 2,664.0**				**$ 904.5**

[1] This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

	December 31, 2024							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Equity securities:								
United States equity	$ 168.4	$ —	$ —	$ 168.4	$ 93.8	$ —	$ —	$ 93.8
International equity	158.2	—	—	158.2	86.4	—	—	86.4
Fixed income securities: [1]								
United States bonds	—	880.1	—	880.1	99.0	205.6	—	304.6
International bonds	—	81.6	—	81.6	—	11.2	—	11.2
	$ 326.6	$ 961.7	$ —	$ 1,288.3	$ 279.2	$ 216.8	$ —	$ 496.0
Investments measured at net asset value:								
Equity securities				414.9				190.4
Fixed income securities				126.0				51.8
Other				795.1				111.8
Total				$ 2,624.3				$ 850.0

[1] This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

The following tables set forth a reconciliation of changes in fair values of pension and OPEB plan assets categorized as Level 3 in the fair value hierarchy:

	United States Bonds	
(in millions)	Pension	OPEB
Beginning balance at January 1, 2025	$ —	$ —
Purchases	**1.4**	**0.1**
Ending balance at December 31, 2025	**$ 1.4**	**$ 0.1**

Cash Flows

We expect to contribute $16.5 million to the pension plans and $2.8 million to the OPEB plans in 2026, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB over the next 10 years:

(in millions)	Pension Benefits	OPEB Benefits
2026	$ 213.5	$ 35.5
2027	203.1	37.6
2028	193.5	38.7
2029	187.5	39.5
2030	182.1	39.8
2031-2035	801.3	197.8

Savings Plans

We sponsor 401(k) savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. The 401(k) savings plans include an Employee Stock Ownership Plan. Certain employees receive a retirement contribution in lieu of receiving a pension benefit. Total costs incurred under all of these plans were $67.3 million, $61.6 million, and $57.5 million in 2025, 2024, and 2023, respectively.

NOTE 21—INVESTMENT IN TRANSMISSION AFFILIATES

We own approximately 60% of ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects. We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. ATC's corporate manager has an 11-member board of directors, and ATC Holdco's corporate manager has a four-member board of directors. We have one representative on each board. Each member of the board has only one vote. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	2025		
(in millions)	ATC	ATC Holdco	Total
Balance at January 1	**$ 2,085.1**	**$ 23.8**	**$ 2,108.9**
Add: Earnings from equity method investment	**209.7**	**6.1**	**215.8**
Add: Capital contributions	**142.4**	**—**	**142.4**
Less: Distributions	**180.2**	**6.4**	**186.6**
Less: Other	**0.1**	**—**	**0.1**
Balance at December 31	**$ 2,256.9**	**$ 23.5**	**$ 2,280.4**

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(in millions)	2024 ATC	2024 ATC Holdco	2024 Total
Balance at January 1	$ 1,980.8	$ 25.1	$ 2,005.9
Add: Earnings from equity method investment	205.4	2.1	207.5
Add: Capital contributions	45.5	—	45.5
Less: Distributions	146.7	3.4	150.1
Add: Other	0.1	—	0.1
Balance at December 31	$ 2,085.1	$ 23.8	$ 2,108.9

(in millions)	2023 ATC	2023 ATC Holdco	2023 Total
Balance at January 1	$ 1,884.6	$ 24.6	$ 1,909.2
Add: Earnings from equity method investment	175.1	2.4	177.5
Add: Capital contributions	63.7	—	63.7
Less: Distributions	142.6	1.9	144.5
Balance at December 31	$ 1,980.8	$ 25.1	$ 2,005.9

The ROE allowed by the FERC helps determine how much transmission owners, such as ATC, earn on their transmission assets as well as how much consumers pay for those assets. In November 2013, a complaint was filed arguing the base ROE for MISO transmission owners was too high. The D.C. Circuit Court of Appeals issued an opinion in August 2022 for this ROE complaint that resulted in ATC recording a reserve for potential refunds based on a 9.88% base ROE. In response to this opinion, the FERC issued an order in October 2024 that required ATC to adopt a 9.98% base ROE. Due to the change between the 9.88% base ROE originally reflected in ATC's reserve and the 9.98% base ROE authorized in the October 2024 FERC order, ATC reduced its refund liability, which increased our pre-tax equity earnings by $20.1 million during 2024.

We pay ATC for network transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. We are also required to initially fund the construction of transmission infrastructure upgrades needed for new generation projects. ATC owns these transmission assets and reimburses us for these costs when the new generation is placed in service.

The following table summarizes our significant related party transactions with ATC during the years ended December 31:

(in millions)	2025	2024	2023
Charges to ATC for services and construction	**$ 20.2**	$ 21.6	$ 17.4
Charges from ATC for network transmission services	**466.9**	413.3	377.5
Refund from ATC related to FERC ROE orders	**5.2**	—	—

As of December 31, 2025 and 2024, our balance sheets included the following receivables and payables for services provided to or received from ATC:

(in millions)	2025	2024
Accounts receivable for services provided to ATC	**$ 1.6**	$ 1.4
Accounts payable for services received from ATC	**38.4**	34.4
Amounts due from ATC for transmission infrastructure upgrades (1)	**32.2**	54.5

(1) The transmission infrastructure upgrades were primarily related to the construction of WE's, WPS's, and UMERC's renewable energy projects.

Summarized financial data for ATC is included in the tables below:

(in millions)	Year Ended December 31 2025	2024	2023
Income statement data			
Operating revenues	**$ 975.0**	$ 911.3	$ 818.9
Operating expenses	**472.6**	442.4	407.6
Other expense, net	**165.8**	137.7	131.7
Net income	**$ 336.6**	$ 331.2	$ 279.6

(in millions)	December 31, 2025	December 31, 2024
Balance sheet data		
Current assets	**$ 137.5**	$ 126.6
Noncurrent assets	**7,590.8**	6,792.6
Total assets	**$ 7,728.3**	$ 6,919.2
Current liabilities	**$ 839.8**	$ 482.4
Long-term debt	**3,156.3**	3,083.4
Other noncurrent liabilities	**638.9**	545.0
Members' equity	**3,093.3**	2,808.4
Total liabilities and members' equity	**$ 7,728.3**	$ 6,919.2

NOTE 22—SEGMENT INFORMATION

Our President and CEO, who is our CODM, reviews financial information presented on a segment basis for purposes of making operating decisions and assessing performance. The CODM regularly reviews net income attributed to common shareholders to measure segment profitability and to allocate resources, including assets, to our businesses. Net income attributed to common shareholders best measures our segment profitability as it reflects all revenues and costs, including the impact on our tax provision from tax credits generated through investments in renewable generation facilities.

Our CODM allocates resources, such as employees, as well as financial and capital resources, to our segments during the annual review of budgets and the capital plan. Our CODM also reviews and revises the resources throughout the year during the monthly forecasting process in order to make timely decisions that align with our overall corporate strategy. The CODM uses each segment's net income to evaluate performance by comparing actual results to budgeted and forecasted amounts, as well as the ROE earned for each utility within the various utility segments.

Segments were determined based on a combination of factors, including the regulatory environment of each geographical jurisdiction in which the segment operates, equity investment interests, as well as the revenue streams for the products or services provided to customers through electric, natural gas, and renewable operations. See Note 4, Operating Revenues, for more information on disaggregation of operating revenues, including intercompany eliminations. The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies.

At December 31, 2025, we reported six segments, which are described below. All of our operations are located within the United States.

- The Wisconsin segment includes the electric and natural gas utility operations of WE, WPS, WG, and UMERC.

- The Illinois segment includes the natural gas utility operations of PGL and NSG.

- The other states segment includes the natural gas utility operations of MERC and MGU and the non-utility operations of MERC.

- The electric transmission segment includes our approximate 60% ownership interest in ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects, and our approximate 75% ownership interest in ATC Holdco, which was formed to invest in transmission-related projects outside of ATC's traditional footprint. See Note 21, Investment in Transmission Affiliates, for more information on ATC and ATC Holdco.

- The non-utility energy infrastructure segment includes:
  - We Power, which owns and leases generating facilities to WE,
  - Bluewater, which owns underground natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities, and
  - WECI, which owns majority interests in multiple renewable generating facilities.

  See Note 2, Acquisitions, for more information on recent WECI acquisitions.

- The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Wisvest, WECC, and WBS.

The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2025, 2024, and 2023.

2025 (in millions)	Utility Operations: Wisconsin	Utility Operations: Illinois	Utility Operations: Other States	Utility Operations: Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
External revenues	$ 7,295.5	$ 1,683.6	$ 527.5	$ 9,506.6	$ —	$ 293.5	$ —	$ —	$ 9,800.1
Intersegment revenues	—	—	—	—	—	476.7	—	(476.7)	—
Fuel and purchased power	1,674.9	—	—	1,674.9	—	—	—	—	1,674.9
Cost of natural gas sold	871.5	508.0	246.3	1,625.8	—	9.6	—	(44.5)	1,590.9
Other operation and maintenance	1,737.9	482.2	104.6	2,324.7	—	95.5	(10.2)	(9.2)	2,400.8
Impairments related to Illinois segment	—	130.0	—	130.0	—	—	—	—	130.0
Depreciation and amortization	1,008.1	259.7	49.8	1,317.6	—	240.2	21.6	(100.9)	1,478.5
Property and revenue taxes	178.7	55.5	26.2	260.4	—	19.6	0.1	—	280.1
Equity in earnings of transmission affiliates	—	—	—	—	215.8	—	—	—	215.8
Other income, net [(1)]	96.5	8.6	0.4	105.5	—	2.8	30.6	(31.0)	107.9
Interest expense	638.7	88.9	19.2	746.8	19.3	123.1	359.0	(353.1)	895.1
Income tax expense (benefit)	226.2	45.8	21.0	293.0	48.9	(122.9)	(101.0)	—	118.0
Preferred stock dividends of subsidiary	1.2	—	—	1.2	—	—	—	—	1.2
Net loss attributed to noncontrolling interests	—	—	—	—	—	3.2	—	—	3.2
Net income (loss) attributed to common shareholders	$ 1,054.8	$ 122.1	$ 60.8	$ 1,237.7	$ 147.6	$ 411.1	$ (238.9)	$ —	$ 1,557.5
Other Segment Disclosures									
Capital expenditures and asset acquisitions	$ 3,860.1	$ 306.1	$ 112.5	$ 4,278.7	$ —	$ 504.7	$ 20.8	$ —	$ 4,804.2
Equity method investments	17.8	—	—	17.8	2,280.4	—	55.7	—	2,353.9
Total assets [(2)]	33,984.7	8,167.7	1,733.3	43,885.7	2,282.8	7,762.9	1,227.6	(3,640.7)	51,518.3

(1) Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

(2) Total assets at December 31, 2025 reflect an elimination of $2,594.8 million for all lease activity between We Power and WE.

2024 *(in millions)*	Utility Operations: Wisconsin	Utility Operations: Illinois	Utility Operations: Other States	Utility Operations: Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
External revenues	$ 6,330.5	$ 1,602.4	$ 449.8	$ 8,382.7	$ —	$ 217.2	$ —	$ —	$ 8,599.9
Intersegment revenues	—	—	—	—	—	474.1	—	(474.1)	—
Fuel and purchased power	1,455.7	—	—	1,455.7	—	—	—	—	1,455.7
Cost of natural gas sold	661.9	376.7	198.6	1,237.2	—	9.1	—	(46.0)	1,200.3
Other operation and maintenance	1,547.9	461.5	93.9	2,103.3	—	75.1	(11.3)	(9.1)	2,158.0
Impairments related to Illinois segment	—	12.1	—	12.1	—	—	—	—	12.1
Depreciation and amortization	919.9	255.4	47.0	1,222.3	—	198.4	22.3	(88.5)	1,354.5
Property and revenue taxes	169.6	59.9	21.0	250.5	—	15.7	0.3	—	266.5
Equity in earnings of transmission affiliates	—	—	—	—	207.5	—	—	—	207.5
Other income, net [1]	146.6	7.6	0.3	154.5	—	1.0	54.4	(31.7)	178.2
Interest expense	637.3	94.7	16.4	748.4	19.4	99.7	310.0	(362.2)	815.3
Gain on debt extinguishments	—	—	—	—	—	—	(23.1)	—	(23.1)
Income tax expense (benefit)	220.5	97.6	18.7	336.8	47.1	(82.4)	(79.5)	—	222.0
Preferred stock dividends of subsidiary	1.2	—	—	1.2	—	—	—	—	1.2
Net loss attributed to noncontrolling interests	—	—	—	—	—	4.1	—	—	4.1
Net income (loss) attributed to common shareholders	$ 863.1	$ 252.1	$ 54.5	$ 1,169.7	$ 141.0	$ 380.8	$ (164.3)	$ —	$ 1,527.2
Other Segment Disclosures									
Capital expenditures and asset acquisitions	$ 2,347.1	$ 343.0	$ 118.3	$ 2,808.4	$ —	$ 945.8	$ 20.6	$ —	$ 3,774.8
Equity method investments	15.7	—	—	15.7	2,108.9	—	67.0	—	2,191.6
Total assets [2]	30,622.7	8,168.8	1,646.0	40,437.5	2,126.0	7,316.0	1,037.3	(3,553.6)	47,363.2

[1] Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

[2] Total assets at December 31, 2024 reflect an elimination of $1,525.4 million for all lease activity between We Power and WE.

2023 *(in millions)*	Utility Operations: Wisconsin	Utility Operations: Illinois	Utility Operations: Other States	Utility Operations: Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
External revenues	$ 6,625.9	$ 1,557.8	$ 519.1	$ 8,702.8	$ —	$ 190.1	$ 0.1	$ —	$ 8,893.0
Intersegment revenues	—	—	—	—	—	476.4	—	(476.4)	—
Fuel and purchased power	1,615.9	—	—	1,615.9	—	—	—	—	1,615.9
Cost of natural gas sold	894.7	443.0	277.2	1,614.9	—	20.5	—	(60.1)	1,575.3
Other operation and maintenance	1,531.3	397.9	94.5	2,023.7	—	80.1	5.8	(9.1)	2,100.5
Impairments related to Illinois segment	—	178.9	—	178.9	—	—	—	—	178.9
Depreciation and amortization	851.5	237.3	43.3	1,132.1	—	188.7	20.9	(77.5)	1,264.2
Property and revenue taxes	179.2	29.9	24.4	233.5	—	16.5	0.2	—	250.2
Equity in earnings of transmission affiliates	—	—	—	—	177.5	—	—	—	177.5
Other income, net [1]	137.6	6.7	0.6	144.9	—	—	53.3	(20.5)	177.7
Interest expense	601.0	88.9	15.9	705.8	19.4	94.3	258.1	(350.2)	727.4
Gain on debt extinguishments	—	—	—	—	—	—	(0.5)	—	(0.5)
Income tax expense (benefit)	237.4	48.6	16.3	302.3	39.0	(68.4)	(68.3)	—	204.6
Preferred stock dividends of subsidiary	1.2	—	—	1.2	—	—	—	—	1.2
Net loss attributed to noncontrolling interests	—	—	—	—	—	1.2	—	—	1.2
Net income (loss) attributed to common shareholders	$ 851.3	$ 140.0	$ 48.1	$ 1,039.4	$ 119.1	$ 336.0	$ (162.8)	$ —	$ 1,331.7
Other Segment Disclosures									
Capital expenditures and asset acquisitions	$ 2,134.4	$ 489.8	$ 103.5	$ 2,727.7	$ —	$ 754.4	$ 25.8	$ —	$ 3,507.9
Equity method investments	14.4	—	—	14.4	2,005.9	—	61.3	—	2,081.6
Total assets [2]	28,527.3	7,970.2	1,571.5	38,069.0	2,006.0	6,404.7	1,100.1	(3,640.1)	43,939.7

[1] Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

[2] Total assets at December 31, 2023 reflect an elimination of $1,630.6 million for all lease activity between We Power and WE.

NOTE 23—VARIABLE INTEREST ENTITIES

The primary beneficiary of a VIE must consolidate the entity's assets and liabilities. In addition, certain disclosures are required for significant interest holders in VIEs.

We assess our relationships with potential VIEs, such as our coal suppliers, natural gas suppliers, coal transporters, natural gas transporters, and other counterparties related to PPAs, investments, and joint ventures. In making this assessment, we consider, along with other factors, the potential that our contracts or other arrangements provide subordinated financial support, the obligation to absorb the entity's losses, the right to receive residual returns of the entity, and the power to direct the activities that most significantly impact the entity's economic performance.

WEPCo Environmental Trust Finance I, LLC

In November 2020, the PSCW issued a financing order approving the securitization of $100 million of undepreciated environmental control costs related to WE's retired Pleasant Prairie power plant, the carrying costs accrued on the $100 million during the securitization process, and the related financing fees. The financing order also authorized WE to form WEPCo Environmental Trust, a bankruptcy-remote special purpose entity, for the sole purpose of issuing ETBs to recover the costs approved in the financing order. WEPCo Environmental Trust is a wholly owned subsidiary of WE.

In May 2021, WEPCo Environmental Trust issued ETBs and used the proceeds to acquire environmental control property from WE. The environmental control property is recorded as a regulatory asset on our balance sheets and includes the right to impose, collect, and receive a non-bypassable environmental control charge from WE's retail electric distribution customers until the ETBs are paid in full and all financing costs have been recovered. The ETBs are secured by the environmental control property. Cash collections from the environmental control charge and funds on deposit in trust accounts are the sole sources of funds to satisfy the debt obligation. The bondholders do not have any recourse to WE or any of WE's affiliates.

WE acts as the servicer of the environmental control property on behalf of WEPCo Environmental Trust and is responsible for metering, calculating, billing, and collecting the environmental control charge. As necessary, WE is authorized to implement periodic adjustments of the environmental control charge. The adjustments are designed to ensure the timely payment of principal, interest, and other ongoing financing costs. WE remits all collections of the environmental control charge to WEPCo Environmental Trust's indenture trustee.

WEPCo Environmental Trust is a VIE primarily because its equity capitalization is insufficient to support its operations. As described above, WE has the power to direct the activities that most significantly impact WEPCo Environmental Trust's economic performance. Therefore, WE is considered the primary beneficiary of WEPCo Environmental Trust, and consolidation is required.

The following table summarizes the impact of WEPCo Environmental Trust on our balance sheets:

(in millions)	December 31, 2025	December 31, 2024
Assets		
Other current assets (restricted cash)	**$ 2.0**	$ 1.5
Regulatory assets	**67.5**	76.5
Other long-term assets (restricted cash)	**0.6**	0.6
Liabilities		
Current portion of long-term debt	**9.3**	9.2
Accounts payable	**0.1**	—
Other current liabilities (accrued interest)	**0.1**	0.1
Long-term debt	**67.4**	76.4

Investment in Transmission Affiliates

We own approximately 60% of ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. We have determined that ATC is a VIE but consolidation is not required since we are not ATC's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC's economic performance. Therefore, we account for ATC as an equity method investment. At December 31, 2025 and 2024, our equity investment in ATC was $2,256.9 million and $2,085.1 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC.

We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. We have determined that ATC Holdco is a VIE but consolidation is not required since we are not ATC Holdco's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC Holdco's economic performance. Therefore, we account for ATC Holdco as an equity method investment. At December 31, 2025 and 2024, our equity investment in ATC Holdco was $23.5 million and $23.8 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 21, Investment in Transmission Affiliates, for more information, including any significant assets and liabilities related to ATC and ATC Holdco recorded on our balance sheets.

NOTE 24—COMMITMENTS AND CONTINGENCIES

We and our subsidiaries have significant commitments and contingencies arising from our operations, including those related to unconditional purchase obligations, environmental matters, and enforcement and litigation matters.

Unconditional Purchase Obligations

Our electric utilities have obligations to distribute and sell electricity to their customers, and our natural gas utilities have obligations to distribute and sell natural gas to their customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

The renewable generation facilities that are part of our non-utility energy infrastructure segment have obligations to distribute and sell electricity through long-term offtake agreements with their customers for all of the energy produced. In order to support these sales obligations, these companies enter into easements and other service agreements associated with the generating facilities.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2025, including those of our subsidiaries:

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2026	2027	2028	2029	2030	Later Years
Electric utility:								
Nuclear	2033	$ 5,045.8	$ 681.6	$ 730.4	$ 782.6	$ 838.5	$ 898.5	$ 1,114.2
Coal supply and transportation	2028	412.1	242.2	127.7	37.0	3.5	1.7	—
Purchased power	2063	335.3	61.6	56.3	52.4	25.6	5.9	133.5
Other	2043	85.5	12.0	12.1	9.6	8.4	8.5	34.9
Natural gas utility:								
Supply and transportation	2048	2,921.3	487.0	478.8	426.8	323.6	203.0	1,002.1
Non-utility energy infrastructure:								
Purchased power	2055	720.7	55.0	56.3	57.6	50.7	48.4	452.7
Natural gas storage and transportation	2048	4.6	3.9	—	0.1	—	—	0.6
Total		$ 9,525.3	$ 1,543.3	$ 1,461.6	$ 1,366.1	$ 1,250.3	$ 1,166.0	$ 2,738.0

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as SO_2, NOx, fine particulates, ozone, mercury, and GHGs; water intake and discharges; management of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

We have continued to pursue a proactive strategy to manage our environmental compliance obligations, including:

- the development of additional sources of renewable electric energy supply, battery storage, and natural gas and LNG storage facilities;
- the addition of improvements for water quality matters such as treatment technologies to meet regulatory discharge limits and improvements to our cooling water intake systems;
- the addition of emission control equipment to existing facilities to comply with ambient air quality standards and federal clean air rules;

- the protection of wetlands and waterways, biodiversity including threatened and endangered species, and cultural resources associated with construction projects;
- the retirement of older coal-fired power plants and conversion to modern, efficient, natural gas generation, super-critical pulverized coal generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired and biomass generating units;
- the remediation of former manufactured gas plant sites;
- the reduction of methane emissions across our natural gas distribution system by upgrading infrastructure; and
- the tracking and reporting of GHG emissions.

Federal Deregulatory Actions

In March 2025, the EPA announced a large-scale deregulatory effort that will likely take multiple years to complete. Of the proposed deregulatory actions, those that would apply to us include actions impacting the Good Neighbor Rule, MATS, the PM2.5 Standard, the GHG Power Plant Rule, the Mandatory Greenhouse Gas Reporting Rule, the ELG, and the CCR Rule. Any EPA actions will require formal rulemaking proceedings and are likely to be subject to legal challenges. We continue to monitor and evaluate these deregulatory actions for potential risks and benefits.

In February 2026, the EPA published a final rule rescinding the 2009 declaration that determined that CO_2 and other GHGs endanger public health and welfare. The "endangerment finding" has been the legal underpinning of a host of climate regulations under the CAA. The rule is expected to face litigation.

Air Quality

Cross State Air Pollution Rule – Good Neighbor Rule

In 2023, the EPA issued a final Good Neighbor Rule, which required significant reductions in ozone-forming emissions of NOx from power plants and industrial facilities. In June 2024, the rule was stayed by the Supreme Court with respect to the specific applicant states, pending ongoing judicial review.

In response to the Supreme Court's order, in November 2024, the EPA administratively stayed the effectiveness of the Good Neighbor Rule through an interim final rule which extends a stay to all states to which the rule originally applied, including states in which we operate. The interim final rule also includes provisions to ensure that covered facilities in states with previously established requirements to mitigate interstate air pollution with respect to the 2008 ozone NAAQS will remain subject to equivalent requirements while the Good Neighbor Rule's effectiveness is stayed. Regardless of the outcome, we believe we are well positioned to comply with either standard. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

Mercury and Air Toxics Standards

The EPA issued the MATS rule to limit emissions of mercury, acid gases, and other hazardous air pollutants. In May 2024, the EPA finalized amendments to the MATS rule (the "2024 Amendments") which among other things, lowered the PM limit from 0.03 lb/MMBtu to 0.01 lb/MMBtu. We believe we are well positioned to comply with the requirements of the 2024 Amendments.

In June 2025, the EPA proposed to repeal the 2024 Amendments which would result in a return of the PM limit to 0.03 lb/MMBtu. In December 2025, the EPA submitted a draft of the rule to the OMB for interagency review. Following completion of the OMB review process, the EPA has stated it expects the rule to be finalized in the first quarter of 2026.

National Ambient Air Quality Standards

Ozone

After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, creating a more stringent standard than the 2008 NAAQS. The 2015 ozone standard lowered the 8-hour limit for ground-level ozone. The EPA's initial ozone nonattainment area designation was effective August 2018, and the attainment status is evaluated every 3 years thereafter until attainment is achieved. The Milwaukee, Sheboygan, and Chicago, IL-IN-WI nonattainment areas did not meet the marginal attainment deadline of August 2021, so in April 2022 the EPA proposed "moderate" nonattainment status based on the 2015 standard. In October 2022, the EPA published its final reclassifications from "marginal" to "moderate" for these areas, effective November 2022.

After the most recent evaluation, the EPA issued a final rule in December 2024 that determined that parts of Southeast Wisconsin failed to attain 2015 ozone NAAQS and consequently would be reclassified from "moderate" to "serious", effective January 2025.

In February 2025, the State of Wisconsin filed a petition for review of this reclassification in the United States Court of Appeals for the Seventh Circuit. Wisconsin subsequently moved for a stay of the reclassification, which was granted in September 2025, pending the Court's review. This means that Southeast Wisconsin has returned to "moderate" status while the underlying lawsuit proceeds.

A nonattainment status of "serious" could have a material adverse effect on future permitting activities for our facilities in applicable locations, including additional costs associated with more strenuous emission control requirements or the need to purchase emission reduction credits.

Particulate Matter

All counties within our service territories are currently in attainment with current 2012 NAAQS for PM2.5. In February 2024, the EPA finalized a rule which lowered the primary (health-based) annual PM2.5 NAAQS from 12 $\mu g/m^3$ to 9 $\mu g/m^3$ (the "2024 PM2.5 Standard"). In February 2025, the WDNR submitted a State Implementation Plan to the EPA recommending Wisconsin be designated as an attainment area under the 2024 PM2.5 Standard. The EPA has not yet issued its attainment designations and has indicated it may extend the designation period. A designation of nonattainment status could impact future permitting activities for facilities in applicable locations, including the potential need for improved or new air pollution control equipment. With our planned transition from coal-fired plants to natural gas-fired plants and renewable generating facilities, we do not expect the 2024 PM2.5 Standard to have a material impact on our units.

In November 2025, the EPA filed a motion with the D.C. Circuit Court of Appeals to vacate the 2024 PM2.5 Standard. The 2024 PM2.5 Standard remains in effect while the motion is being considered. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

New Source Performance Standards

Nitrogen Oxides

In January 2026, the EPA released a pre-publication version of its final rule regulating NOx for CTs constructed, modified, or reconstructed after December 13, 2024. The final rule, which became effective January 15, 2026 and established NOx emissions standards for several subcategories of new, modified, and reconstructed CTs based on the size, rates of utilization, design efficiency, and fuel type of these turbines. We believe we are well positioned to comply with this rule.

Climate Change

Pursuant to the final GHG Power Plant Rule, there are no applicable GHG emission standards for coal plants until the end of 2031. Thereafter, the applicable standard is dependent upon the unit's retirement date. Numerous parties have challenged the GHG Power Plant Rule through litigation pending in the D.C. Circuit Court of Appeals, and it is being held in abeyance at the request of the parties.

In March 2024, the EPA announced it had removed regulations on existing natural gas CTs from the rule. At that time, the EPA indicated it would work on new rulemaking in phases, focusing on CO_2 emissions, as well as NOx and hazardous air pollutants emissions. See New Source Performance Standards - Nitrogen Oxides above for a discussion of the EPA's recent actions addressing NOx.

In June 2025, the EPA issued a proposed rule that contains a primary and an alternative proposal which, depending on which version is finalized, would result in either a broad repeal of GHG emissions standards or a more narrow repeal of the rule's carbon capture and storage requirements. We do not expect either alternative to have any impact on its current capital plan. Any final rule would likely be subject to litigation. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

In April 2024, the EPA issued its final Mandatory Greenhouse Gas Reporting Rule, which includes updates to the global warming potentials to determine CO_2 equivalency for threshold reporting and the addition of a new section regarding energy consumption. In its current form, the rule will impact the reporting required for our electric generation facilities, LDCs, and underground natural gas storage facilities. In May 2024, the EPA also issued its final rule to amend reporting requirements for petroleum and natural gas systems. Under the current form of this rule, new leak emission factors and reporting requirements for large release events will impact the reporting required for our LDCs and underground natural gas storage facilities; however, under the Federal Deregulatory Actions discussion above, in September 2025, the EPA released a proposal to amend the GHG Reporting Program to permanently remove program obligations for most source categories, including our generation facilities. The EPA is also proposing to suspend program reporting requirements that would be applicable to our underground storage, LNG, and transmission affiliates until 2034. We continue to monitor the status of these deregulatory actions.

Our capital plan includes the planned retirement of older, fossil-fueled generation, to be replaced with natural gas-fired generation and zero-carbon-emitting renewables. We have retired nearly 2,500 MWs of fossil-fueled generation since the beginning of 2018. We expect to retire approximately 900 MWs of additional coal-fired generation by the end of 2031. In conjunction with our new capital plan, we and the other co-owners of Columbia Units 1 and 2 currently plan to continue coal operations at these units through at least 2029, and continue to evaluate the conversion of both units to natural gas. See Note 7, Property, Plant, and Equipment, for more information related to Columbia Units 1 and 2 and our planned power plant retirements. We have a long-term goal to achieve net carbon-neutral electric generation by the end of 2050. We expect to achieve this goal by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. As part of our path toward this goal, we started implementing co-firing with natural gas at the ERGS coal-fired units and at Weston Unit 4 in 2025. We expect to use coal only as a backup fuel by the end of 2030 and to be in a position to eliminate coal as an energy source by the end of 2032.

We also continue to focus on methane emission reductions by improving and upgrading our natural gas distribution systems and using RNG throughout our natural gas utility systems.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule

The Clean Water Act Cooling Water Intake Structure Rule requires the location, design, construction, and capacity of cooling water intake structures at existing power plants reflect the BTA for minimizing adverse environmental impacts. The rule applies to all of our existing generating facilities with cooling water intake structures, except for the ERGS units, which were permitted and received a final BTA determination under the rules governing new facilities.

Other than OCPP Units 7 and 8, we have received final or interim BTA determinations for all generation facilities where applicable. We believe existing technology at OCPP Units 7 and 8 also meets the rule requirements for BTA and anticipate that the units will receive that determination when their Wisconsin Pollutant Discharge Elimination System permit is reissued, which is expected in 2026.

Steam Electric Effluent Limitation Guidelines

The EPA's 2024 Supplemental ELG Rule (the "2024 ELG Rule") established ZLD requirements for bottom ash transport water, flue gas desulfurization, and combustion residual leachate wastewaters at coal-fueled facilities. The 2024 ELG Rule also established a new subcategory, providing an alternative compliance pathway for facility owners that commit to the PCCC at a particular facility by December 31, 2034. In exchange for this commitment, ZLD technologies will not be required and less stringent standards will apply at applicable facilities. The 2024 ELG Rule also allows owners of coal-fired units who opted into a cessation of coal subcategory to operate beyond the end of 2034 if needed for reliability concerns (i.e., energy emergencies and reliability must run agreements) as determined by the United States DOE, a public utility commission, or independent system operator. Based on current electric generation resource planning, in December 2025, we filed Notice of Planned Participations to opt into the PCCC subcategory for certain of our past and current coal-fueled facilities.

In December 2025, the EPA published a final rule, effective March 2, 2026, that extends the deadline for facility owners to opt into a subcategory under the 2024 ELG Rule, allowing them more time to assess potential compliance pathways to continue producing low-cost electricity into the future while meeting wastewater standards.

When the deadline extension rule was proposed, the EPA also solicited public comments related to the economic achievability and technical availability of ZLD technologies. Additional ELG rulemaking is anticipated that may lead to substantive changes to the ZLD technology-based requirements established in the 2024 ELG Rule.

In addition, numerous parties have challenged the 2024 ELG Rule through litigation in *SWEPCO v. U.S. EPA* pending in the United States Court of Appeals for the Eighth Circuit, which has been held in abeyance since February 2025. The 2024 ELG Rule, as well as the deadline extension rule, remain in effect during the pendency of the legal challenge. The outcome of this case may affect our compliance plans.

Land Quality

Manufactured Gas Plant Remediation

We have identified sites at which our utilities or a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Our natural gas utilities are responsible for the environmental remediation of these sites. We are working with the EPA as well as various state jurisdictions, as applicable, in our investigation and remediation planning and efforts. These sites are at various stages of investigation, monitoring, remediation, and closure.

The future costs for detailed site investigation, future remediation, and monitoring are dependent upon several variables including, among other things, the extent of remediation, changes in technology, and changes in regulation. Historically, our regulators have allowed us to recover incurred costs, net of insurance recoveries and recoveries from potentially responsible parties, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

We have established the following regulatory assets and reserves for manufactured gas plant sites as of December 31:

(in millions)	2025	2024
Regulatory assets for environmental remediation costs	**$ 566.0**	$ 570.1
Reserves for future environmental remediation	**484.1**	445.8

Coal Combustion Residuals Rule

An EPA rule for CCR that applies to landfills, historic fill sites, and projects where CCR was placed at a power plant site became effective in November 2024. The rule also regulates previously exempt closed landfills.

We anticipate this rule will have an impact on some of our coal ash landfills, requiring additional remediation that is not currently required under the state programs. We expect the cost of additional remediation would be recoverable through future rates.

The rule is being challenged through litigation pending in the D.C. Circuit Court of Appeals. In December 2025, the D.C. Circuit Court of Appeals granted the EPA's motion to extend the ongoing abeyance while the EPA reconsiders certain aspects of the rule. In February 2026, the EPA published a final rule extending certain deadlines and making various corrections to the 2024 CCR rule. The EPA has stated it plans to publish a new final rule by the end of 2026. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

Renewables, Efficiency, and Conservation

Wisconsin Legislation

In 2005, Wisconsin enacted Act 141, which established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources annually. WE and WPS have achieved their required renewable energy percentages of 8.27% and 9.74%, respectively, by constructing various wind and solar facilities, a biomass facility, and by also relying on renewable energy purchases. WE and WPS continue to review their renewable energy portfolios and acquire cost-effective renewables as needed to meet their requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and each utility funds the program based on 1.2% of its annual retail operating revenues.

Michigan Legislation

In December 2016, Michigan enacted Act 342, which required 12.5% of the state's electric energy to come from renewables for 2019 and 2020, and energy optimization (efficiency) targets up to 1% annually. The renewable requirement increased to 15.0% for 2021 and beyond. UMERC was in compliance with its requirements under this statute as of December 31, 2025. The legislation continues to allow recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

In November 2023, Michigan enacted Acts 229, 231 and 235. The acts require electric providers to file a renewable energy plan every two years and to set renewable energy portfolio targets from now until 2040. The proposed renewable energy targets include 15% through 2029, 50% from 2030 through 2034, and 60% renewable energy by 2035 and thereafter. The bill also sets clean energy standards of 80% from 2035 through 2039 and 100% after 2040. The acts only allow natural gas to count as clean energy if it is accompanied with carbon capture and storage. The new acts also revise the requirement a utility must meet in filing its energy waste reduction plans. They require a utility to file a plan every two years until 2025, then every three years thereafter. In February 2025, we filed an AREP with the MPSC addressing UMERC's compliance with the Act 235 renewable portfolio standards. At the same time, we are working with a coalition of members of the Michigan legislature to seek exemption from Act 235 for our new RICE units. In December 2025, the MPSC issued an order denying UMERC's AREP, requiring UMERC to file a new AREP in October 2026.

Enforcement and Litigation Matters

We and our subsidiaries are involved in legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although we are unable to predict the outcome of these matters, management believes that appropriate reserves have been established and that final settlement of these actions will not have a material impact on our financial condition or results of operations.

NOTE 25—SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides additional information regarding our statements of cash flows:

	Year Ended December 31		
(in millions)	**2025**	**2024**	**2023**
Cash paid for interest, net of amount capitalized	**$ 858.5**	$ 785.7	$ 653.4
Cash received for income taxes, net	**(281.3)**	(264.2)	(58.9)
Significant non-cash investing and financing transactions:			
Accounts payable related to construction costs	**232.0**	285.7	171.3
Common stock issued for stock-based compensation plans	**3.2**	6.4	—
Increase in receivables related to property damage insurance proceeds	**3.5**	2.3	3.5
Increase in receivables for corporate-owned life insurance proceeds	**—**	5.8	1.4
Liabilities accrued for software licensing agreements	**21.1**	0.2	—

Cash, Cash Equivalents, and Restricted Cash

The statements of cash flows include our activity related to cash, cash equivalents, and restricted cash. The following table reconciles the cash, cash equivalents, and restricted cash amounts reported within the balance sheets at December 31 to the total of these amounts shown on the statements of cash flows:

(in millions)	**2025**	**2024**	**2023**
Cash and cash equivalents	**$ 27.6**	$ 9.8	$ 42.9
Restricted cash included in other current assets	**9.1**	5.3	70.1
Restricted cash included in other long-term assets	**34.2**	27.1	52.2
Cash, cash equivalents, and restricted cash	**$ 70.9**	$ 42.2	$ 165.2

Our restricted cash primarily consisted of the following:

- Cash held in the Integrys rabbi trust, which is used to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans.

- Cash on deposit in financial institutions that is restricted to satisfy the requirements of certain debt agreements at WECI Wind Holding I, WECI Wind Holding II, WECI Energy Holding III, and WEPCo Environmental Trust.

- Cash related to WECI's ownership interests in certain renewable generation projects. These projects are required to deposit into an escrow account in order to fund future decommissioning.

NOTE 26—REGULATORY ENVIRONMENT

Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Wisconsin Gas LLC

Very Large Customer and Bespoke Resources Tariffs

In March 2025, WE filed an application with the PSCW requesting approval to implement a VLC Tariff and a Bespoke Resources Tariff. WE subsequently filed testimony in October 2025 slightly modifying the initial proposals. Under these proposed inter-connected tariffs, VLCs (new customers using 500 MWs or more, such as large data centers) will have access to reliable power to meet their needs and will directly pay for the electricity they consume, along with the power plants and distribution facilities built to serve them and operating and transmission costs allocated to their usage. The proposed tariffs are designed so that the costs associated with these VLCs are not subsidized by or shifted to residential or business customers.

The two new tariffs will work in tandem as VLCs will be required to sign a service agreement and subscribe to a portion of one or more "Bespoke Resources," including renewable generation facilities, battery storage, and natural gas generation units. Under these agreements, if a VLC terminates or downsizes its plans, it will still be required to pay for the Bespoke Resources and dedicated distribution facilities that have been built to support its forecasted load, unless the facilities can be repurposed, subject to PSCW approval. Service agreements under the Bespoke Resources Tariff will be effective for the depreciable life of the resource, except for wind or solar resources which will have a term of 20 years. As currently proposed, the ROE (can range from 10.48% to 10.98% as agreed upon with the customer) and equity ratio (57%) will both be fixed for the entire term of the agreement, and the revenue and costs recovered through the tariffs will be excluded from future rate case proceedings and earnings sharing mechanisms.

We expect a decision from the PSCW in the second quarter of 2026. Prior to the PSCW approving the tariffs, for infrastructure investments that have not received regulatory approval, WE requires VLCs to enter into payment and cancellation agreements which obligate the VLC to reimburse WE for all costs associated with projects, including any associated costs incurred by ATC for transmission infrastructure projects, requested by the customer until service agreements are executed under the approved tariffs. Reimbursement is required if, among other things, the VLC terminates the payment and cancellation agreement or reduces its anticipated load, or regulatory approval is not received for the construction of a project.

2025 and 2026 Rates

In April 2024, WE, WPS, and WG filed requests with the PSCW to increase their retail electric, natural gas, and steam rates, as applicable. The primary drivers of the requested increases in electric rates were continued capital investments to transition our generation fleets from coal to renewables and natural gas-fueled generation, increased costs driven by higher inflation and interest rates, and the recovery of regulatory assets previously approved by the PSCW. The requested increases in natural gas rates were driven by the companies' ongoing capital investments in reliability and safety projects, including LNG storage facilities, as well as the impacts from higher inflation and increased interest rates.

In December 2024, the PSCW issued final written orders approving electric, natural gas, and steam base rate increases, effective January 1, 2025 and 2026, as applicable. The final written orders reflected the following:

	WE	WPS	WG
2025 rate increase			
Electric [1]	$ 144.0 million / 4.2%	$ 55.1 million / 4.5%	N/A
Gas	$ 41.3 million / 7.1%	$ 14.9 million / 3.8%	$ 34.5 million / 4.2%
Steam	$ 1.5 million / 5.0%	N/A	N/A
2026 rate increase [2]			
Electric [1]	$ 169.5 million / 4.5%	$ 30.0 million / 2.3%	N/A
Gas	$ 29.8 million / 4.5%	$ 13.5 million / 3.1%	$ 23.5 million / 2.6%
ROE	9.8%	9.8%	9.8%
Common equity component average on a financial basis	53.0%	53.0%	53.0%

(1) Amounts reflect the impact to our Wisconsin retail electric operations and include the incremental decrease resulting from updated fuel costs.

(2) The 2026 rate increases are incremental to the previously authorized revenue plus the approved rate increases for 2025.

Effective January 1, 2025, WE was required to implement a new earnings sharing mechanism, under which, if WE earns above its authorized ROE: (i) it retains 100.0% of earnings for the first 15 basis points above the authorized ROE; (ii) 50.0% of the next 25 basis points is required to be refunded to ratepayers; and (iii) 100.0% of any remaining excess earnings is required to be refunded to ratepayers.

WPS and WG were required to maintain their then current earnings sharing mechanism. Under this mechanism, if the utility earns above its authorized ROE: (i) the utility retains 100.0% of earnings for the first 15 basis points above the authorized ROE; (ii) 50.0% of the next 60 basis points is required to be refunded to ratepayers; and (iii) 100.0% of any remaining excess earnings is required to be refunded to ratepayers.

2024 Limited Rate Case Re-Opener

In accordance with their rate orders approved by the PSCW in December 2022, WE, WPS, and WG filed requests for limited electric and natural gas rate case re-openers, as applicable, with the PSCW in May 2023. The WE and WPS limited electric rate case re-openers included updated fuel costs and revenue requirements for the generation projects that were previously approved by the PSCW and were placed into service in 2023 or were expected to be placed into service in 2024. WE's limited electric re-opener also included the projected savings from the retirement of the OCPP Units 5 and 6, which were retired in May 2024. WE and WG also filed a request for a limited natural gas rate case re-opener to reflect the additional revenue requirements associated with their previously approved LNG projects. WE's and WG's LNG projects were placed into service in November 2023 and February 2024, respectively.

In December 2023, the PSCW issued final written orders approving electric and natural gas rate increases and decreases, effective January 1, 2024. The final orders reflected the following:

	WE	WPS	WG
2024 incremental rate increases (decreases)			
Electric [1]	$ 82.2 million / 2.5%	$ (32.7) million / (2.6)%	N/A
Gas	$ 23.9 million / 4.5%	N/A	$ 21.6 million / 2.8%

(1) Amounts reflect the impact to our Wisconsin retail electric operations and include any incremental increases (WE) or decreases (WPS) resulting from updated fuel costs.

The utilities' ROE and common equity component averages were not addressed in the limited rate case re-openers.

2023 and 2024 Rates

In April 2022, WE, WPS, and WG filed requests with the PSCW to increase their retail electric, natural gas, and steam rates, as applicable. These requests were updated in July 2022 to reflect new developments that impacted the original proposals. The requested increases in electric rates were driven by capital investments in new wind, solar, and battery storage; capital investments in natural gas generation; reliability investments, including grid hardening projects to bury power lines and strengthen WE's distribution system against severe weather; and changes in wholesale business with other utilities. Many of these investments had already been approved by the PSCW. The requested increases in natural gas rates primarily related to capital investments previously approved by the PSCW, including LNG storage for our natural gas distribution system.

In December 2022, the PSCW issued final written orders approving electric, natural gas, and steam base rate increases, effective January 1, 2023. The final orders reflected the following:

	WE	WPS	WG
2023 base rate increase			
Electric	$ 283.5 million / 9.1%	$ 120.5 million / 9.8%	N/A
Gas	$ 46.1 million / 9.6%	$ 26.4 million / 7.1%	$ 46.5 million / 6.4%
Steam	$ 7.6 million / 35.3%	N/A	N/A
ROE	9.8%	9.8%	9.8%
Common equity component average on a financial basis	53.0%	53.0%	53.0%

In addition to the above, the final orders included the following terms:

- The utilities kept their then current earnings sharing mechanisms, under which, if a utility earned above its authorized ROE: (i) the utility retained 100.0% of earnings for the first 15 basis points above the authorized ROE; (ii) 50.0% of the next 60 basis points was refunded to ratepayers; and (iii) 100.0% of any remaining excess earnings was required to be refunded to ratepayers.
- WE and WPS were required to complete an analysis of alternative recovery scenarios for generating units that will be retired prior to the end of their useful life.
- WE and WPS were not allowed to propose any changes to their real time pricing rates for large commercial and industrial electric customers through the end of 2024.
- WE and WPS were required to lower monthly residential and small commercial electric customer fixed charges by $1.00 and $3.33, respectively, from previously authorized rates.
- WE and WPS were required to offer an additional voluntary renewable energy pilot for commercial and industrial customers.
- WE and WPS were required to continue to work with PSCW staff and other interested parties to develop alternative low income assistance programs. WE and WPS also collectively contributed $4.0 million to the Keep Wisconsin Warm Fund.
- WE, WPS, and WG were required to implement escrow accounting treatment for pension and OPEB costs. As a result, they defer as a regulatory asset or liability, the difference between actual pension and OPEB costs and those included in rates until recovery or refund is authorized in a future rate proceeding.
- As discussed above, WE and WPS were authorized to file a limited electric rate case re-opener for 2024, and WE and WG were authorized to file a limited natural gas rate case re-opener for 2024.

The Peoples Gas Light and Coke Company and North Shore Gas Company

2026 Rate Application

In January 2026, PGL and NSG filed requests with the ICC to increase their natural gas base rates. They are requesting rate increases of $201.3 million (20.95%) and $12.7 million (12.2%), respectively. The requested rate increases are primarily driven by capital investments made to strengthen the safety and reliability of each utility’s natural gas distribution system. PGL's rate request includes the estimated revenue requirements associated with its PRP projects. As discussed below, projects completed under PGL's PRP are to meet the ICC's directive to retire all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. PGL's rate request includes the revenue requirements associated with approximately $360 million of capital investments planned under its PRP in 2027. Higher operating costs, driven by inflation, and increases in the cost of capital, also drove the requested rate increases. Both companies are requesting an ROE of 10.10% and a common equity component average of 54.0%.

An ICC decision is anticipated in the fourth quarter of 2026, with new rates expected to be effective by January 1, 2027.

2023 Rate Order

In January 2023, PGL and NSG filed requests with the ICC to increase their natural gas base rates. The requested rate increases were primarily driven by capital investments made to strengthen the safety and reliability of each utility's natural gas distribution system. PGL was also seeking to recover costs incurred to upgrade its natural gas storage field and operations facilities and to continue improving customer service. PGL did not request an extension of the QIP rider as PGL returned to the traditional rate making process to recover the costs of necessary infrastructure improvements.

In November 2023, the ICC issued final written orders approving base rate increases for PGL and NSG. The written orders were subsequently amended for various technical corrections. The amended written orders approved the following base rate increases:

- A $304.6 million (43.5%) base rate increase for PGL's natural gas customers, effective December 1, 2023. This amount includes the recovery of costs that were previously being recovered under its QIP rider.

- An $11.0 million (11.6%) base rate increase for NSG's natural gas customers. The new rates at NSG were not effective until February 1, 2024 as changes were required to NSG's billing system as a result of the final rate order.

The ICC approved an authorized ROE of 9.38% for both PGL and NSG, and set the common equity component average at 50.79% and 52.58% for PGL and NSG, respectively.

As part of its decisions, the ICC, among other things, disallowed $236.2 million of capital costs related to the construction and improvement of PGL's shops and facilities and $1.7 million of capital costs related to NSG's construction of a gas infrastructure project. In addition, the ICC ordered PGL to pause spending on its projects to upgrade its natural gas delivery system until the ICC had a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level.

In December 2023, PGL and NSG filed an application for rehearing with the ICC requesting reconsideration of various issues in the ICC's November 2023 written orders. The ICC granted PGL and NSG a limited-scope rehearing focused exclusively on the authorized spending for the completion of projects to upgrade PGL's natural gas delivery system that started in 2023 and emergency repairs needed to ensure the safety and reliability of the delivery system. In May 2024, the ICC issued a written order on the rehearing. The order approved $28.5 million of additional spending for emergency work, representing a $1.6 million increase to PGL's annual revenue requirement.

As the ICC did not grant a rehearing on the disallowance of PGL's and NSG's capital costs, we recorded a $178.9 million non-cash impairment of our property, plant, and equipment during the fourth quarter of 2023. This amount included $177.2 million of previously incurred disallowed costs at PGL related to its shops and facilities, and the $1.7 million of capital costs disallowed at NSG. The remaining disallowance of capital costs at PGL related to expected future spend.

In June 2024, PGL and NSG filed a petition with the Illinois Appellate Court for review of the November 2023 and May 2024 orders. The appeal includes the ICC's $237.9 million combined disallowance of capital costs at PGL and NSG discussed above, along with the $116.0 million disallowance of capital investments needed to meet safety and reliability requirements of PGL's natural gas delivery system. Although the ICC ordered PGL to complete safety and reliability work in 2024, it denied the recovery of these costs in the current rates.

In accordance with the November 2023 rate order, the ICC initiated a proceeding in January 2024 to determine the optimal method and a prudent investment level for replacing aging natural gas infrastructure. In February 2025, the ICC issued an order setting expectations for PGL's prospective operations. The ICC directed us to focus on retiring all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. The ICC also indicated that failure to comply with this directive could subject us to civil penalties under Illinois statute. PGL is working to retire this cast and ductile iron pipe through its PRP. Costs incurred under the PRP will be evaluated for prudency by the ICC in future rate cases. In addition, the program will be overseen by a safety monitor hired by the ICC. As discussed above, PGL initiated a general rate case proceeding in January 2026, which we anticipate will provide further regulatory clarity before we significantly increase our spend associated with the PRP.

Illinois Riders

Uncollectible Expense Adjustment Rider

The rates of PGL and NSG include a UEA rider for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The UEA rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency by the ICC. In May 2023, the ICC issued a written order on PGL's and NSG's 2018 UEA rider reconciliation. The order required a $15.4 million and $0.7 million refund to customers at PGL and NSG, respectively. These amounts were refunded over a period of nine months, which began on September 1, 2023. Upon appeal by PGL and NSG, the Illinois Appellate Court affirmed the ICC order and the related disallowance. The Illinois Supreme Court denied a subsequent petition for review and reversal of the order in March 2025.

As of December 31, 2025, there can be no assurance that all costs incurred under the UEA rider during the open reconciliation years will be deemed recoverable by the ICC. Future disallowances by the ICC could be material. The combined annual costs of PGL and NSG included in the rider, which reflect uncollectible write-offs in excess of what is recovered in base rates, have ranged from $10 million to $40 million. However, see Uncollectible Expense Adjustment and Qualifying Infrastructure Plant Riders Settlement below for information on a proposed settlement that would resolve all open proceedings.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides natural gas utilities with a cost recovery mechanism that allows collection, through a surcharge on customer bills, of prudently incurred costs to upgrade Illinois natural gas infrastructure. In January 2014, the ICC approved a QIP rider for PGL, which was in effect until December 1, 2023. As discussed above, PGL has returned to the traditional rate-making process for recovery of these costs, and they are now included in PGL's base rates.

Costs previously incurred under PGL's QIP rider are still subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In August 2024, the ICC issued a final order on PGL's 2016 annual reconciliation, which included a disallowance of $14.8 million of certain capital costs. PGL recorded a pre-tax charge to income of $25.3 million during the third quarter of 2024 related to the disallowance and the previously recognized return on and of these investments. The charge was recorded on the income statement as a $12.9 million reduction in revenues for the amounts previously collected from customers, a $12.1 million increase to operating expenses for the impairment of PGL's property, plant, and equipment, and a $0.3 million increase to interest expense related to the amounts due to customers. In October 2024, PGL filed a petition with the Illinois Appellate Court for review of the ICC's August 2024 order; however, in January 2026, PGL filed an unopposed motion to stay the appeal, which was granted by the court.

PGL's QIP reconciliations from 2017 through 2023 are still pending. Future disallowances by the ICC could be material. The aggregate capital costs included in the rider during the open reconciliation years, along with any previously recognized return on these investments, totaled approximately $3.0 billion as of December 31, 2025. However, see Uncollectible Expense Adjustment and Qualifying Infrastructure Plant Riders Settlement below for information on a proposed settlement that would resolve all open proceedings.

Uncollectible Expense Adjustment and Qualifying Infrastructure Plant Riders Settlement

In February 2026, PGL and NSG agreed on the terms of a proposed settlement with the Illinois Attorney General that, if approved by the ICC, would resolve all open proceedings related to the UEA and QIP riders. PGL and NSG agreed to refund $49.0 million and $1.0 million, respectively, to customers as bill credits over a period of three years between 2026 and 2028 to resolve the open UEA proceedings. In order to resolve the open QIP proceedings, PGL agreed to permanently remove $130.0 million of qualified infrastructure investment costs from rate base starting in 2027 and to refund $75.0 million to customers as bill credits over a period of three years between 2026 and 2028. As a result of this agreement, we recorded a $205.0 million charge to income during the fourth quarter of 2025. The charge was recorded as a $130.0 million impairment to PGL's net property, plant, and equipment and a $75.0 million reduction to revenues. The total of the rate base reduction and the obligation to refund amounts to customers through bill credits recorded on our balance sheet at December 31, 2025 is $255.0 million. This includes the $205.0 million charge to income recorded during 2025 and a $50.0 million charge to income recorded in prior years. This proposed settlement is subject to ICC approval following a public review process.

Minnesota Energy Resources Corporation

2023 Rate Order

In November 2022, MERC initiated a rate proceeding with the MPUC to increase its retail natural gas base rates. In December 2022, the MPUC approved MERC's request for interim rates totaling $37.0 million, subject to refund. The interim rates went into effect on January 1, 2023.

In November 2023, the MPUC issued a written order approving a settlement agreement MERC reached with certain intervenors. The settlement agreement reflected a natural gas base rate increase of $28.8 million (7.1%), along with a 9.65% ROE and a common equity component average of 53.0%. The natural gas rate increase was primarily driven by increased capital investments as well as inflationary pressure on operating costs. Under the terms of the settlement agreement, MERC will continue the use of its decoupling mechanism for residential customers, and it will be expanded to include certain small commercial and industrial customers.

Final rates went into effect on March 1, 2024. MERC’s customers were entitled to an $8.9 million refund due to the interim rate increase exceeding the final approved rate increase, which was retroactive to January 1, 2023. These amounts were refunded to customers during the second quarter of 2024.

Michigan Gas Utilities Corporation

2026 Rate Application

On December 19, 2025, MGU provided notification to the MPSC of its intent to file an application requesting an increase to its natural gas rates. The application is expected to be filed in March 2026 and to request new rates be effective January 1, 2027. MGU is currently in the process of evaluating its rate request.

2024 Rate Order

In March 2024, MGU filed a request with the MPSC to increase its retail natural gas base rates. In September 2024, the MPSC issued a final order approving a settlement agreement, which authorized MGU to increase its natural gas base rates by $7.0 million (3.88%). The rate increase was primarily driven by inflationary pressure on capital projects and operating and maintenance costs and the significant increase in interest rates over the past few years. The rate increase reflected a 9.86% ROE and a common equity component average of 50.0%. The new rates became effective January 1, 2025. The order also authorized MGU to defer any expenses incurred to implement the PHMSA's proposed rulemaking titled "Gas Pipeline Leak Detection and Repair."

2023 Rate Order

In March 2023, MGU filed a request with the MPSC to increase its retail natural gas base rates. In August 2023, the MPSC issued a written order approving a comprehensive settlement that resolved all issues in MGU's rate case. The key terms of the settlement agreement included:

- a natural gas base rate increase of $9.9 million (4.7%);
- an ROE of 9.8%;
- a common equity component average of 51.0%; and,
- a continuation of the existing MRP rider, effective January 1, 2025 through 2027, including forecasted increased costs for those projects. MRP costs were recovered in base rates in 2024.

The rate increase was primarily driven by capital investments made to strengthen the safety and reliability of MGU's natural gas distribution system and to provide service to additional customers. Inflationary pressure on operating costs also contributed to the rate increase. The new rates were effective January 1, 2024.

Upper Michigan Energy Resources Corporation

Amended Renewable Energy Plan

In accordance with Michigan Public Act 235, UMERC filed an AREP with the MPSC in February 2025. UMERC's AREP addressed its compliance with the Act 235 renewable portfolio standards and its proposal to recover the projected compliance costs through an incremental renewable energy surcharge. The projected compliance costs included the purchase of Michigan-sourced renewable energy credits and the revenue requirements for UMERC's previously approved investment in Renegade, a 100 MW utility-scale solar-powered electric generating facility, and any other incremental renewable generation resources required to meet the Act 235 renewable portfolio standards. On December 18, 2025, the MPSC issued an order denying UMERC's AREP and requiring UMERC to file a new AREP by October 15, 2026.

Renegade is currently interconnected and delivering power to MISO, and it is expected to achieve commercial operation in the first quarter of 2026. The estimated cost of Renegade is approximately $226 million. As UMERC's proposal to recover the annual revenue requirement of Renegade through a renewable energy surcharge was denied, UMERC will recover a portion of these costs through its power supply cost recovery mechanism, and the MPSC advised UMERC to seek deferral accounting treatment for the remainder. UMERC filed its request for deferral accounting with the MPSC on January 27, 2026.

2024 Rate Order

In May 2024, UMERC filed a request with the MPSC to increase its electric base rates for non-mine customers. In October 2024, the MPSC issued a final order approving a settlement agreement, which authorized UMERC to increase electric base rates for non-mine customers by $6.6 million (8.2%). The new rates became effective January 1, 2025. The rate increase reflected a 9.86% ROE and a common equity component average of 50.0%. The rate increase was primarily driven by the construction of the now in-service RICE generation facilities located in the Upper Peninsula of Michigan and a reduction in sales volumes resulting from the implementation of limited retail choice since UMERC’s predecessor utilities last reset rates. A reduction of operation and maintenance costs partially offset these impacts.

NOTE 27—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2025	2024	2023
AFUDC-Equity	**$ 99.8**	$ 59.8	$ 59.1
Gains from investments held in rabbi trust	**8.1**	11.7	13.7
Interest income	**5.9**	17.2	3.9
Non-service components of net periodic benefit costs	**2.7**	83.7	97.7
Earnings (losses) from equity method investments [1]	**(10.4)**	4.7	(1.1)
Other, net	**1.8**	1.1	4.4
Other income, net	**$ 107.9**	$ 178.2	$ 177.7

[1] Amounts do not include equity earnings of transmission affiliates as those earnings are shown as a separate line item on the income statements.

NOTE 28—NEW ACCOUNTING PRONOUNCEMENTS

Improvements to Interim Reporting

In December 2025, the FASB issued ASU No. 2025-11, Interim Reporting (Topic 270) Narrow-Scope Improvements. The amendments clarify interim disclosure requirements and the applicability of Topic 270. The amendments include a comprehensive list of interim disclosures that are currently required under GAAP. The amendments also include a disclosure principle that requires entities to disclose events since the end of the last annual reporting period that have a material impact on the entity. Finally, the amendments clarify the types of interim reporting and the form and content of interim financial statements in accordance with GAAP. The amendments are effective for interim periods within annual periods beginning after December 15, 2027, with early adoption permitted. We are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

Accounting for Government Grants

In December 2025, the FASB issued ASU No. 2025-10, Government Grants (Topic 832) Accounting for Government Grants Received by Business Entities. The amendments establish the accounting for a government grant received by a business entity, including guidance for a grant related to an asset and a grant related to income. The amendments also require disclosures, including the nature of the government grant received, the accounting policies used to account for the grant, and significant terms and conditions of the grant. The amendments are effective for annual periods beginning after December 15, 2028, and interim periods within those annual periods, with early adoption permitted. We are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU No. 2024-03, Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures (Subtopic 220-40) Disaggregation of Income Statement Expenses. The amendments require disclosure of certain costs and expenses in the notes to financial statements, which are disaggregated from relevant expense captions on the income statement. The amendments also require additional qualitative disclosures of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. Finally, the amendments require disclosure of the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. The amendments are effective for annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027, with early adoption permitted. We plan to adopt these amendments beginning with our fiscal year ending on December 31, 2027, and are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective: (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act; and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our and our subsidiaries' internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our and our subsidiaries' internal control over financial reporting was effective as of December 31, 2025.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fourth quarter of 2025 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

For Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm, attesting to the effectiveness of our internal controls over financial reporting, see Section A of Item 8.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2025, none of our directors or officers (as defined in Rule 16a-1 under the Exchange Act) adopted or terminated any contract, instruction, or written plan for the purchase or sale of our securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement" (as defined in Item 408 of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Proposal 1: Election of Directors – Terms Expiring in 2027 – 2026 Director Nominees for Election," "Annual Meeting Attendance and Voting Information – Stockholder Nominees and Proposals," "Governance – Board Committees – Audit and Oversight," and "Governance – Additional Governance Matters – Insider Trading Policy" in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Shareholders to be held May 7, 2026 (the "2026 Annual Meeting Proxy Statement") is incorporated herein by reference. Also see "Information about our Executive Officers" in Part I of this report.

We have adopted a written code of ethics, referred to as our Code of Business Conduct, with which all of our directors, executive officers, and employees, including the principal executive officer, principal financial officer, and principal accounting officer, must comply with. We have posted our Code of Business Conduct on our website, www.wecenergygroup.com. We have not provided any waiver to the Code for any director, executive officer, or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on our website or in a current report on Form 8-K.

Our website, www.wecenergygroup.com, also contains our Corporate Governance Guidelines and the charters of our Audit and Oversight, Corporate Governance, and Compensation Committees.

Our Code of Business Conduct, Corporate Governance Guidelines, and committee charters are also available without charge to any shareholder of record or beneficial owner of our common stock by writing to the corporate secretary, Margaret C. Kelsey, at our principal business office, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201.

ITEM 11. EXECUTIVE COMPENSATION

The information under "Compensation Discussion and Analysis," "Executive Compensation Tables," "Governance – Director Compensation," and "Governance – Compensation Committee Interlocks and Insider Participation" in the 2026 Annual Meeting Proxy Statement is incorporated herein by reference.

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

The security ownership information called for by Item 12 of Form 10-K is incorporated herein by reference to this information included under "WEC Energy Group Common Stock Ownership" in the 2026 Annual Meeting Proxy Statement.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans as of December 31, 2025:

Plan Type	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants, and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Shares Reflected in Column (a)) (c)
Equity Compensation Plans Approved by Security Holders	2,568,777	$ 86.66	6,503,836 [1]
Equity Compensation Plans Not Approved by Security Holders	N/A	N/A	N/A
Total	2,568,777	$ 86.66	6,503,836

(1) Includes shares available for future issuance under our Omnibus Stock Incentive Plan, all of which could be granted as awards of stock options, stock appreciation rights, performance units, restricted stock, or other stock based awards.

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

The information under "Governance – Additional Governance Matters – Related Party Transactions," "Proposal 1: Election of Directors – Terms Expiring in 2027 – Board Composition – Independence," and "Governance – Board Committees" in the 2026 Annual Meeting Proxy Statement is incorporated herein by reference. A full description of the guidelines our Board uses to determine director independence is located in Appendix A of our Corporate Governance Guidelines, which can be found on the Corporate Governance section of our Company's website at www.wecenergygroup.com/govern/governance.htm.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our AOC under "Proposal 2: Ratification of Deloitte & Touche LLP as Independent Auditors for 2026 – Independent Auditors' Fees and Services" in the 2026 Annual Meeting Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements and Reports of Independent Registered Public Accounting Firm Included in Part II of This Report

2. Financial Statement Schedules Included in Part IV of This Report

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. Exhibits and Exhibit Index

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to WEC Energy Group, Inc. (File No. 001-09057). An asterisk (*) indicates that the exhibit has previously been filed with the SEC and is incorporated herein by reference. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K is identified below by two asterisks (**) following the description of the exhibit.

Number	Exhibit	
3	**Articles of Incorporation and By-laws**	
	3.1*	Restated Articles of Incorporation of WEC Energy Group, as amended effective May 21, 2012. (Exhibit 3.1 to Wisconsin Energy Corporation's 06/30/12 Form 10-Q.)
	3.2*	Articles of Amendment to the Restated Articles of Incorporation of WEC Energy Group, as amended. (Exhibit 3.1 to WEC Energy Group's 06/29/15 Form 8-K.)
	3.3*	Articles of Amendment to the Restated Articles of Incorporation of WEC Energy Group, as amended, dated May 9, 2024. (Exhibit 3.1 to WEC Energy Group's 06/30/2024 Form 10-Q.)
	3.4*	Bylaws of WEC Energy Group, as amended to January 19, 2023. (Exhibit 3.1 to WEC Energy Group's 01/20/23 Form 8-K.)

Number	Exhibit
4	**Instruments defining the rights of security holders, including indentures**

4.1* Reference is made to Article III of the Restated Articles of Incorporation and the Bylaws of WEC Energy Group. (See Exhibits 3.1 and 3.3 above.)

4.2* Description of WEC Energy Group's Common Stock. (Exhibit 4.2 to WEC Energy Group's 12/31/2024 Form 10-K.)

Indentures and Securities Resolutions:

4.3* Indenture for Debt Securities of WE (the "WE Indenture"), dated December 1, 1995. (Exhibit (4)-1 under File No. 1-1245, WE's 12/31/95 Form 10-K.)

4.4* Securities Resolution No. 1 of WE under the WE Indenture, dated December 5, 1995. (Exhibit (4)-2 under File No. 1-1245, WE's 12/31/95 Form 10-K.)

4.5* Securities Resolution No. 3 of WE under the WE Indenture, dated May 27, 1998. (Exhibit (4)-1 under File No. 1-1245, WE's 06/30/98 Form 10-Q.)

4.6* Securities Resolution No. 5 of WE under the WE Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to WE's Registration Statement on Form S-3. (File No. 333-101054), filed May 6, 2003.)

4.7* Securities Resolution No. 7 of WE under the WE Indenture, dated as of November 2, 2006. (Exhibit 4.1 under File No. 1-1245, WE's 11/02/06 Form 8-K.)

4.8* Securities Resolution No. 12 of WE under the WE Indenture, dated as of December 5, 2012. (Exhibit 4.1 under File No. 1-1245, WE's 12/05/12 Form 8-K.)

4.9* Securities Resolution No. 14 of WE under the WE Indenture, dated as of May 12, 2014. (Exhibit 4.1 under File No. 1-1245, WE's 05/12/14 Form 8-K.)

4.10* Securities Resolution No. 16 of WE under the WE Indenture, dated as of November 13, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 11/13/15 Form 8-K.)

4.11* Securities Resolution No. 17 of WE under the WE Indenture, dated as of October 1, 2018. (Exhibit 4.1 under File No. 1-1245, WE's 10/01/18 Form 8-K.)

4.12* Securities Resolution No. 19 of WE under the WE Indenture, dated as of June 8, 2021. (Exhibit 4.1 under File No. 1-1245, WE's 06/15/21 Form 8-K.)

4.13* Securities Resolution No. 20 of WE under the WE Indenture, dated as of September 14, 2022. (Exhibit 4.1 under File No. 1-1245, WE's 09/22/22 Form 8-K.)

4.14* Securities Resolution No. 21 of WE under the WE Indenture, dated as of May 7, 2024. (Exhibit 4.1 under File No. 1-1245, WE's 05/14/2024 Form 8-K.)

4.15* Securities Resolution No. 22 of WE under the WE Indenture, dated as of September 9, 2024. (Exhibit 4.1 under File No. 1-1245, WE's 09/13/2024 Form 8-K.)

4.16* Securities Resolution No. 23 of WE under the WE Indenture, dated as of September 18, 2025. (Exhibit 4.1 under File No. 1-1245, WE's 09/25/2025 Form 8-K.)

4.17* Securities Resolution No. 24 of WE under the WE Indenture, dated as of December 2, 2025. (Exhibit 4.1 under File No. 1-1245, WE's 12/05/2025 Form 8-K.)

4.18* Indenture for Debt Securities of Wisconsin Energy Corporation (the "Wisconsin Energy Indenture"), dated as of March 15, 1999, between WEC Energy Group and The Bank of New York Mellon Trust Company, N.A. (as successor to First National Bank of Chicago), as Trustee. (Exhibit 4.46 to Wisconsin Energy Corporation's 03/25/99 Form 8-K.)

4.19* Securities Resolution No. 4 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, dated as of March 17, 2003. (Exhibit 4.12 filed with Post-Effective Amendment No. 1 to Wisconsin Energy Corporation's Registration Statement on Form S-3 (File No. 333-69592), filed March 20, 2003.)

Number	Exhibit
4.20*	Securities Resolution No. 10 of WEC Energy Group under the Wisconsin Energy Indenture, effective as of October 5, 2020. (Exhibit 4.1 to WEC Energy Group's 10/05/20 Form 8-K.)
4.21*	Securities Resolution No. 12 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of December 6, 2021. (Exhibit 4.1 to WEC Energy Group's 12/13/21 Form 8-K.)
4.22*	Securities Resolution No. 13 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of September 22, 2022. (Exhibit 4.1 to WEC Energy Group's 9/27/22 Form 8-K.)
4.23*	Securities Resolution No. 14 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of January 9, 2023. (Exhibit 4.1 to WEC Energy Group's 01/11/23 Form 8-K.)
4.24*	Securities Resolution No. 15 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of September 5, 2023. (Exhibit 4.1 to WEC Energy Group's 09/12/23 Form 8-K.)
4.25*	Securities Resolution No. 16 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of November 19, 2024. (Exhibit 4.25 to WEC Energy Group's 12/31/2024 Form 10-K.)
4.26*	Securities Resolution No. 17 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of November 19, 2024. (Exhibit 4.26 to WEC Energy Group's 12/31/2024 Form 10-K.)
4.27*	Securities Resolution No. 18 of WEC Energy Group under the Wisconsin Energy Indenture, dated November 3, 2025. (Exhibit 4.1 to WEC Energy Group's 11/06/2025 Form 8-K.)
4.28*	Indenture dated as of May 28, 2024, between WEC Energy Group and The Bank of New York Mellon Trust Company, N.A. as Trustee, providing for the issuance of the Convertible Senior Notes due 2027. (Exhibit 4.1 to WEC Energy Group's 05/28/24 Form 8-K.)
4.29*	Indenture dated as of May 28, 2024, between WEC Energy Group and The Bank of New York Mellon Trust Company, N.A. as Trustee, providing for the issuance of the Convertible Senior Notes due 2029. (Exhibit 4.3 to WEC Energy Group's 05/28/24 Form 8-K.)
4.30*	Indenture dated as of June 10, 2025, between WEC Energy Group and The Bank of New York Mellon Trust Company, N.A. as Trustee, providing for the issuance of the Convertible Senior Notes Due 2028. (Exhibit 4.1 to WEC Energy Group's 06/10/2025 Form 8-K.)
4.31*	Indenture, dated as of December 1, 1998, between WPS and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Exhibit 4A to Form 8-K filed December 18, 1998) (File No. 1-3016).
4.32*	First Supplemental Indenture, dated as of December 1, 1998, between WPS and Firstar Bank Milwaukee, N.A., National Association (Exhibit 4C to Form 8-K filed December 18, 1998) (File No. 1-3016).
4.33*	Fifth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 30, 2006) (File No. 1-3016).
4.34*	Ninth Supplemental Indenture, dated as of December 1, 2012, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 29, 2012) (File No. 1-3016).
4.35*	Tenth Supplemental Indenture, dated as of November 1, 2013, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 18, 2013) (File No. 1-3016).
4.36*	Thirteenth Supplemental Indenture, dated as of August 14, 2019, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed August 14, 2019) (File No. 1-3016).
4.37*	Fourteenth Supplemental Indenture, dated as of November 18, 2021, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 18, 2021) (File No. 1-3016).
4.38*	Sixteenth Supplemental Indenture, dated as of December 6, 2024, by and between WPS and U.S. Bank Trust Company, National Association (successor to Firstar Bank, Milwaukee, N.A., National Association) (Exhibit 4.1 to Form 8-K filed December 6, 2024) (File No. 1-3016).

Number	Exhibit
4.39*	Seventeenth Supplemental Indenture, dated as of January 8, 2026, by and between WPS and U.S. Bank Trust Company, National Association (successor to Firstar Bank, Milwaukee, N.A., National Association) (Exhibit 4.1 to Form 8-K filed January 8, 2026) (File No. 1-3016).
	The forgoing list of exhibits does not include certain unregistered long-term debt instruments of the Registrant and its subsidiaries where the total amount of securities authorized to be issued under the instrument does not exceed 10 percent of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant agrees pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreements and instruments.
10	**Material Contracts**
10.1*	WEC Energy Group Supplemental Pension Plan, Amended and Restated Effective as of January 1, 2018.**
10.2*	Legacy Wisconsin Energy Corporation Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2018.**
10.3*	WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2018.**
10.4*	Amendment dated as of December 20, 2023 to the WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2018.** (Exhibit 10.4 to WEC Energy Group's 12/31/2023 Form 10-K.)**
10.5*	Legacy Wisconsin Energy Corporation Directors' Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.4 to WEC Energy Group's 12/31/16 Form 10-K.)**
10.6*	WEC Energy Group Directors' Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.5 to WEC Energy Group's 12/31/16 Form 10-K.)**
10.7*	WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2018.**
10.8*	WEC Energy Group Supplemental Long Term Disability Plan, Amended and Restated Effective as of January 1, 2017.**
10.9*	WEC Energy Group Short-Term Performance Plan, Amended and Restated Effective as of January 1, 2019.**
10.10*	Wisconsin Energy Corporation 2014 Rabbi Trust by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 23, 2015, regarding the trust established to provide a source of funds to assist in meeting the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy Corporation or its subsidiaries and various plan participants. (Exhibit 10.13 to Wisconsin Energy Corporation's 12/31/14 Form 10K.)**
10.11*	Letter Agreement by and between WEC Energy Group and Xia Liu, dated March 24, 2020. (Exhibit 10.2 to WEC Energy Group's 03/31/20 Form 8-K.)**
10.12*	Letter Agreement by and between Wisconsin Energy Corporation and Robert Garvin, dated January 31, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/11 Form 10-Q.)**
10.13*	Letter Agreement by and between WEC Energy Group and Margaret C. Kelsey, dated as of July 19, 2017. (Exhibit 10.1 to WEC Energy Group's 09/30/17 Form 10-Q.)**
10.14*	Retention Agreement by and between WEC Energy Group and Scott J. Lauber, dated February 21, 2022. (Exhibit 10.16 to WEC Energy Group's 12/31/21 Form 10-K.)**
10.15*	Letter Agreement between WEC Energy Group and Michael Hooper, dated March 7, 2024. (Exhibit 10.1 to WEC Energy Group's 03/12/24 Form 8-K.)**

Number		Exhibit
	10.16.1*	WEC Energy Group Omnibus Stock Incentive Plan, Amended and Restated effective as of January 1, 2016. (Exhibit 10.19 to WEC Energy Group's 12/31/15 Form 10-K.)**
	10.16.2*	WEC Energy Group Omnibus Stock Incentive Plan, amended and restated effective as of May 6, 2021. (Exhibit 10.1 to WEC Energy Group's 5/11/21 Form 8-K.)**
	10.17*	WEC Energy Group Performance Unit Plan, amended and restated effective as of January 1, 2023. (Exhibit 10.1 to WEC Energy Group's 12/02/22 Form 8-K.)**
	10.18*	2016 WEC Energy Group Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.29 to WEC Energy Group's 12/31/15 Form 10-K.)**
	10.19*	Non-Qualified Stock Option Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 06/30/21 Form 10-Q.)**
	10.20*	Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.3 to WEC Energy Group's 06/30/21 Form 10-Q.)**
	10.21*	Director Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.5 to WEC Energy Group's 06/30/21 Form 10-Q.)**
	10.22*	PWGS I Facility Lease Agreement between PWG, as Lessor, and WE, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to WE's 06/30/03 Form 10-Q (File No. 001-01245).)
	10.23*	PWGS II Facility Lease Agreement between PWGS, as Lessor, and WE, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to WE's 06/30/03 Form 10-Q (File No. 001-01245).)
	10.24*	ER I Facility Lease Agreement between ERGS, as Lessor, and WE, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
	10.25*	ER II Facility Lease Agreement between ERGS, as Lessor, and WE, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
	10.26*	Point Beach PPA between FPL Energy Point Beach, LLC and WE, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q.)
	10.27*	Letter Agreement between WE and FPL Energy Point Beach, LLC dated October 31, 2007, which amends the PPA. (Exhibit 10.45 to Wisconsin Energy Corporation's 12/31/07 Form 10-K.)
	10.28*	Integrys Energy Group, Inc. Deferred Compensation Plan, as Amended and Restated Effective January 1, 2016. (Exhibit 10.1 to WEC Energy Group's 06/30/16 Form 10-Q.)**
	10.29*	Integrys Energy Group, Inc. Pension Restoration and Supplemental Retirement Plan, as Amended and Restated Effective January 1, 2017. (Exhibit 10.1 to WEC Energy Group's 06/30/17 Form 10-Q.)**
19	**Insider Trading Policies and Procedures**	
	19.1	Corporate Securities Trading Policy.
21	**Subsidiaries of the Registrant**	
	21.1	Subsidiaries of WEC Energy Group.
23	**Consents of Experts and Counsel**	
	23.1	Deloitte & Touche LLP – Milwaukee, WI, Consent of Independent Registered Public Accounting Firm for WEC Energy Group.

Number	Exhibit	
31	**Rule 13a-14(a) / 15d-14(a) Certifications**	
	31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	**Section 1350 Certifications**	
	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97	**Policy Relating to Recovery of Erroneously Awarded Compensation**	
	97.1*	Incentive-Based Compensation Clawback Policy ("Rule 10D-1 Policy"). (Exhibit 97.1 to WEC Energy Group's 12/31/2023 Form 10-K.)**
101	**Interactive Data File**	
	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
	101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase
	101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase
	101.LAB	Inline XBRL Taxonomy Extension Label Linkbase
	101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase
104	**Cover Page Interactive Date File (formatted as Inline XBRL and contained in Exhibit 101)**	

ITEM 16. FORM 10-K SUMMARY

None.

SCHEDULE I
CONDENSED PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2025	2024	2023
Operating expenses	**$ 3.6**	$ 5.4	$ 2.5
Equity earnings of subsidiaries	**1,819.2**	1,724.2	1,502.5
Other income, net	**26.5**	32.0	19.6
Interest expense	**399.3**	333.6	260.8
Gain on debt extinguishments	**—**	(23.1)	—
Income before income taxes	**1,442.8**	1,440.3	1,258.8
Income tax benefit	**114.7**	86.9	72.9
Net income attributed to common shareholders	**$ 1,557.5**	$ 1,527.2	$ 1,331.7

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

B. STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2025	2024	2023
Net income attributed to common shareholders	**$ 1,557.5**	$ 1,527.2	$ 1,331.7
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of realized derivative gains to net income, net of tax	**(0.2)**	(0.3)	(0.3)
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**0.2**	—	(0.2)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.1**	0.1	0.1
Defined benefit plans, net	**0.3**	0.1	(0.1)
Other comprehensive income (loss) from subsidiaries, net of tax	**0.1**	0.1	(0.5)
Other comprehensive income (loss), net of tax	**0.2**	(0.1)	(0.9)
Comprehensive income attributed to common shareholders	**$ 1,557.7**	$ 1,527.1	$ 1,330.8

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

C. BALANCE SHEETS

At December 31 *(in millions)*	2025	2024
Assets		
Current assets		
Cash and cash equivalents	**$ 0.1**	$ —
Accounts receivable from related parties	**3.2**	2.7
Notes receivable from related parties	**63.0**	63.2
Prepaid income taxes	**14.9**	16.3
Current assets	**81.2**	82.2
Long-term assets		
Investments in subsidiaries	**22,222.1**	19,809.0
Note receivable from WECI	**460.0**	300.0
Other	**56.0**	23.2
Long-term assets	**22,738.1**	20,132.2
Total assets	**$ 22,819.3**	$ 20,214.4
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 702.9**	$ 382.7
Current portion of long-term debt	**1,350.0**	620.0
Accounts payable to related parties	**5.0**	3.1
Notes payable to related parties	**778.4**	580.9
Other	**69.5**	69.4
Current liabilities	**2,905.8**	1,656.1
Long-term liabilities		
Long-term debt	**6,280.2**	6,135.4
Other	**19.7**	28.0
Long-term liabilities	**6,299.9**	6,163.4
Common shareholders' equity	**13,613.6**	12,394.9
Total liabilities and equity	**$ 22,819.3**	$ 20,214.4

The accompanying notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

D. STATEMENTS OF CASH FLOWS

Year Ended December 31 ***(in millions)***	**2025**	**2024**	**2023**
Operating activities			
Net income attributed to common shareholders	**$ 1,557.5**	$ 1,527.2	$ 1,331.7
Reconciliation to cash provided by operating activities			
Equity income in subsidiaries, net of distributions	**(669.2)**	(931.8)	(566.8)
Deferred income taxes, net	**(21.5)**	(2.1)	(3.8)
Gain on debt extinguishments	**—**	(23.1)	—
Change in –			
Accounts receivable from related parties	**(0.5)**	—	(2.0)
Prepaid income taxes	**1.4**	(16.3)	35.4
Other current assets	**—**	0.2	(0.1)
Accounts payable to related parties	**1.9**	0.2	0.9
Accrued interest	**1.3**	(3.6)	42.1
Other current liabilities	**(0.8)**	(0.6)	(0.7)
Other, net	**18.4**	15.5	14.4
Net cash provided by operating activities	**888.5**	565.6	851.1
Investing activities			
Capital contributions to subsidiaries	**(2,277.7)**	(1,273.9)	(1,807.4)
Return of capital from subsidiaries	**537.9**	846.6	175.2
Short-term notes receivable from related parties, net	**0.2**	(47.2)	14.9
Issuance of long-term note receivable to WECI	**(160.0)**	—	—
Other, net	**(14.7)**	—	—
Net cash used in investing activities	**(1,914.3)**	(474.5)	(1,617.3)
Financing activities			
Exercise of stock options	**39.1**	23.7	6.3
Issuance of common stock, net	**761.9**	163.4	—
Purchase of common stock	**(1.3)**	(3.2)	(16.6)
Dividends paid on common stock	**(1,147.8)**	(1,056.2)	(984.2)
Issuance of long-term debt	**1,500.0**	2,475.0	2,050.0
Retirement of long-term debt	**(620.0)**	(1,473.7)	(700.0)
Change in commercial paper	**320.2**	(314.3)	297.3
Short-term notes payable to related parties, net	**197.5**	121.3	127.1
Payments for debt extinguishment and issuance costs	**(23.7)**	(27.0)	(13.3)
Other, net	**—**	(0.1)	(0.4)
Net cash provided by (used in) financing activities	**1,025.9**	(91.1)	766.2
Net change in cash and cash equivalents	**0.1**	—	—
Cash and cash equivalents at beginning of year	**—**	—	—
Cash and cash equivalents at end of year	**$ 0.1**	$ —	$ —

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

SCHEDULE I
CONDENSED PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

E. NOTES TO PARENT COMPANY FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For Parent Company only presentation, investments in subsidiaries are accounted for using the equity method. We use the cumulative earnings approach for classifying distributions received in the statements of cash flows.

The condensed Parent Company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of WEC Energy Group, Inc. appearing in this Annual Report on Form 10-K.

NOTE 2—CASH DIVIDENDS RECEIVED FROM SUBSIDIARIES

Dividends received from our subsidiaries during the years ended December 31 were as follows:

(in millions)	**2025**	2024	2023
WE	**$ 600.0**	$ 240.0	$ 370.0
We Power	**175.6**	225.3	192.8
WECI [(1)]	**152.5**	127.2	93.7
WG	**100.0**	80.0	171.0
ATC Holding	**73.9**	104.6	86.8
UMERC	**23.0**	15.0	21.0
Bluewater	**20.0**	—	—
WEC Investments, LLC	**4.3**	—	—
Wispark [(2)]	**0.7**	0.3	0.4
Total	**$ 1,150.0**	$ 792.4	$ 935.7

(1) We also received amounts classified as return of capital of $534.5 million, $843.9 million, and $171.6 million from WECI during the years ended December 31, 2025, 2024, and 2023, respectively.

(2) We also received amounts classified as return of capital of $2.9 million, $2.7 million, and $3.6 million from Wispark during the years ended December 31, 2025, 2024, and 2023, respectively.

NOTE 3—LONG-TERM DEBT

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2025:

(in millions)	
2026	$ 1,350.0
2027	1,762.5
2028	1,850.0
2029	862.5
2030	300.0
Thereafter	1,550.0
Total	$ 7,675.0

WECC is our subsidiary and has $50.0 million of long-term notes outstanding. In a Support Agreement between WECC and us, we agreed to make sufficient liquid asset contributions to WECC to permit WECC to service its debt obligations as they become due.

NOTE 4—FAIR VALUE MEASUREMENTS

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value as of December 31:

	2025		2024	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term notes receivable from WECI	**$ 460.0**	**$ 464.6**	$ 300.0	$ 300.0
Long-term debt, including current portion	**7,630.2**	**7,922.9**	6,755.4	6,776.0

The fair value of our long-term notes receivable and long-term debt are categorized within Level 2 of the fair value hierarchy.

NOTE 5—GUARANTEES

The following table shows our outstanding guarantees on behalf of our subsidiaries:

		Expiration		
(in millions)	Total Amounts Committed at December 31, 2025	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting business operations [1]	**$ 309.6**	$ 74.9	$ 11.0	$ 223.7
Standby letters of credit [2]	**140.9**	30.7	30.0	80.2
Surety bonds [3]	**46.5**	46.4	0.1	—
Other guarantees [4]	**9.6**	—	—	9.6
Total guarantees	**$ 506.6**	$ 152.0	$ 41.1	$ 313.5

(1) Consists of $233.5 million, $39.0 million, $17.0 million, $10.1 million, $6.0 million, and $4.0 million of guarantees to support the business operations of WECI, MERC, MGU, Bluewater, NSG, and UMERC, respectively.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(3) Primarily for environmental remediation, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Related to workers compensation coverage for which a liability was recorded on our balance sheets.

NOTE 6—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2025	2024	2023
Cash paid for interest	**$ 382.8**	$ 324.2	$ 209.1
Cash received for income taxes, net	**(92.9)**	(66.7)	(104.5)
Significant non-cash equity transaction:			
Issuance of long-term note receivable to WECI	**—**	300.0	430.0
Repayment of long-term note receivable to WECI	**—**	430.0	—

NOTE 7—SHORT-TERM NOTES RECEIVABLE FROM RELATED PARTIES

The following table shows our outstanding short-term notes receivable from related parties as of December 31:

(in millions)	2025	2024
UMERC	**$ 62.9**	$ 63.2
Wispark	**0.1**	—
Total	**$ 63.0**	$ 63.2

NOTE 8—SHORT-TERM NOTES PAYABLE TO RELATED PARTIES

The following table shows our outstanding short-term notes payable to related parties as of December 31:

(in millions)	2025	2024
Integrys	$ **515.3**	$ 327.0
WECC	**112.0**	111.1
WBS	**97.3**	90.4
Bluewater	**53.8**	52.4
Total	**$ 778.4**	$ 580.9

SCHEDULE II
WEC ENERGY GROUP, INC.
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts ***(in millions)***	**Balance at Beginning of Period**	**Expense [1]**	**Deferral**	**Net Write-offs [2]**	**Balance at End of Period**
December 31, 2025	**$ 162.8**	**$ 142.8**	**$ (23.8)**	**$ (133.1)**	**$ 148.7**
December 31, 2024	$ 193.5	$ 104.9	$ 35.8	$ (171.4)	$ 162.8
December 31, 2023	199.3	72.0	88.3	(166.1)	193.5

(1) Net of recoveries.

(2) Represents amounts written off to the reserve, net of adjustments to regulatory assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WEC ENERGY GROUP, INC.

		By /s/ SCOTT J. LAUBER
Date:	February 20, 2026	Scott J. Lauber
		President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ SCOTT J. LAUBER	February 20, 2026
Scott J. Lauber, President and Chief Executive Officer, and Director -- Principal Executive Officer	
/s/ XIA LIU	February 20, 2026
Xia Liu, Executive Vice President and Chief Financial Officer -- Principal Financial Officer	
/s/ WILLIAM J. GUC	February 20, 2026
William J. Guc, Vice President and Controller -- Principal Accounting Officer	
/s/ GALE E. KLAPPA	February 20, 2026
Gale E. Klappa, Non-Executive Chairman of the Board	
/s/ WARNER L. BAXTER	February 20, 2026
Warner L. Baxter, Director	
/s/ AVE M. BIE	February 20, 2026
Ave M. Bie, Director	
/s/ DANNY L. CUNNINGHAM	February 20, 2026
Danny L. Cunningham, Director	
/s/ WILLIAM M. FARROW, III	February 20, 2026
William M. Farrow, III, Director	
/s/ CRISTINA A. GARCIA-THOMAS	February 20, 2026
Cristina A. Garcia-Thomas, Director	
/s/ MARIA C. GREEN	February 20, 2026
Maria C. Green, Director	
/s/ THOMAS K. LANE	February 20, 2026
Thomas K. Lane, Independent Lead Director	
/s/ JOHN D. LANGE	February 20, 2026
John D. Lange, Director	
/s/ ULICE PAYNE, JR.	February 20, 2026
Ulice Payne, Jr., Director	
/s/ MARY ELLEN STANEK	February 20, 2026
Mary Ellen Stanek, Director	
/s/ GLEN E. TELLOCK	February 20, 2026
Glen E. Tellock, Director	

Exhibit 19.1

WEC Energy Group, Inc.
Corporate Securities Trading Policy

Introduction
The purchase or sale of securities while aware of material, non-public information, or the disclosure of material, non-public information to others who then trade in securities of WEC Energy Group or its subsidiaries (collectively, the "Company"), is prohibited by the federal securities laws. Insider trading violations are pursued vigorously by the U.S. Securities and Exchange Commission ("SEC") and Department of Justice and are punished severely. While the regulatory authorities concentrate their efforts on the individuals who trade, or who tip inside information to others who trade, the federal securities laws also impose potential liability on companies and other "controlling persons" if they fail to take reasonable steps to prevent insider trading by Company personnel.

The purpose of this policy is to promote compliance with applicable securities laws and to help all Company personnel, including directors, officers and other employees, avoid the severe consequences associated with violations of insider trading laws. The policy also is intended to prevent even the appearance of improper conduct by any such Company personnel.

Company personnel may not trade in any type of Company securities while in possession of material, non- public information (other than pursuant to a pre-approved 10b5-1 trading plan), as more fully described in this policy.

Directors, officers and certain other designated employees of the Company may only trade in Company securities during designated trading windows and must first obtain pre-clearance from the General Counsel before doing so, as described under the heading Additional Restrictions and Guidelines for Directors, Officers, and Certain Other Persons Designated by the General Counsel.

The policy sets forth additional minimum standards Company personnel must follow when trading in Company securities.

The policy sets forth additional minimum standards Company personnel must follow when trading in Company securities.

This policy is not intended to serve as legal advice. If you have any questions or concerns, you should consult with the General Counsel or seek the advice of legal counsel as to the law and its application to your specific situation.

Applicability
Except as otherwise provided, all directors, officers and other active employees of the Company, as well as their immediate families and members of their household, are subject to the policies set forth herein.

Policy Statement
It is the policy of the Company that no director, officer or other employee of the Company (a) may directly or through family members or other persons or entities, trade any Company security while in possession of material, non-public information relating to the Company (other than pursuant to a pre-approved 10b5-1 trading plan); (b) may pass material, non-public information on to others inside or outside the Company, including family and friends; or (c) who, in the course of working for the Company, learns of material, non-public information about a company with which the Company does business, including a customer or supplier of the Company, or a company that is involved in a potential transaction with the Company, may trade in that company's securities until the information becomes public or is no longer material.

Trading activity includes transactions involving stock; derivative securities, such as put and call options; and debt securities, such as bonds, notes and debentures.

Transactions that may be necessary or justifiable for independent reasons (such as the need to raise money for an emergency expenditure) are not exempt from the policy. The securities laws do not recognize such mitigating circumstances.

It is also the policy of the Company that the Company itself will not engage in transactions in securities of the Company while aware of material non-public information relating to the Company or its securities.

Twenty-Twenty Hindsight: Remember, anyone scrutinizing your transactions will be doing so after the fact, with the benefit of hindsight. As a practical matter, before engaging in any transaction, you should carefully consider how enforcement authorities and others might view the transaction in hindsight.

Directors, officers and certain employees of the Company designated by the Board of Directors and/or the General Counsel are subject to trading windows and must obtain pre-clearance from the General Counsel or her/his designee before buying or selling any securities of the Company. See heading Additional Restrictions and Guidelines for Directors, Officers, and Certain Other Persons Designated by the General Counsel.

Definitions and Explanations

a) "Material" Information

Under Company policy and United States laws, information is material if:

- A reasonable investor would consider the information important in determining whether to buy, hold or sell securities; or
- The information, whether positive or negative, would likely affect the market price of a company's securities.

While it is not possible to define all categories of material information, some examples of information that ordinarily would be regarded as material are:

- Projections of future earnings or losses, or other earnings guidance;
- Significant write-downs and additions to reserves for bad debts;
- Earnings that are inconsistent with the consensus expectations of the investment community;
- Impending bankruptcy or the existence of severe liquidity problems;
- A pending or proposed merger, acquisition or tender offer;
- A pending or proposed acquisition or disposition of a significant asset;
- A change in dividend policy, the declaration of a stock split, or an offering of additional equity securities;
- A change in senior management or extraordinary management developments;
- The gain or loss of a significant customer or supplier;
- Cybersecurity risks and incidents, including vulnerabilities and breaches; and
- Major litigation.

Information may be material even if it relates to future, speculative or contingent events. Non-public information could be material even with respect to companies that do not have publicly traded stock, such as those with outstanding bonds or bank loans.

b) "Non-public" Information

Information is considered to be non-public unless it has been adequately disclosed to the public, which means that the information must be *publicly disseminated and sufficient time* must have passed for the securities markets to digest the information. You may not attempt to "beat the market" by trading simultaneously with, or shortly after, the official release of material information. To avoid the appearance of impropriety, as a general rule, information should not be considered fully absorbed by the marketplace until after the first full trading day after the information is released. If, for example, the Company were to make an announcement during the day on a Monday, you should not trade in the Company's securities until the market opens Wednesday. If an announcement is made prior to the market opening on a Friday, Monday generally would be the first eligible trading day. Despite this general rule, individuals subject to trading windows may not trade until the trading window opens, which generally occurs two full trading days after earnings are released. You should presume that information is non-public unless you can point to its official release by the Company in at least one of the following ways:

- Public filings with the SEC;
- Issuance of press releases;
- Meetings with members of the press and the public; or
- External website.

It is important to note that information is not necessarily public merely because it has been discussed in the press, which will sometimes report rumors.

Confidential Corporate Information

The Company has strict guidelines and safeguards that are stated in its Financial Communications Disclosure Policy, Code of Business Conduct, Information Security Policy, and this policy, that prohibit all employees and directors from sharing confidential corporate information with anyone other than those whose job responsibilities require them to know such information.

c) "Tipping" of Material, Non-Public Information is Prohibited
The Company prohibits the sharing of confidential corporate information with those whose job does not require such information. It is also illegal for you or anyone else to convey material, non-public information to another ("tipping") if you know or have reason to believe that the person will misuse such information by trading securities based on that information or pass such information onto others. This applies regardless of whether the "tippee" is related to you or is an entity, such as a trust or a corporation, and regardless of whether you receive any monetary benefit from the tippee.

Trading on or conveying material, non-public information may also breach contractual obligations assumed by the Company to or on behalf of others. Apart from contractual remedies (such as damages and injunctions), severe, and possibly irreparable, damage to the reputation of the Company may result from trading on, tipping or other improper use of material, non-public information.

d) Transactions by Family Members
This policy also applies to your family members who reside with you (including a spouse, a child living with you or away at college, stepchildren, grandchildren, parents, stepparents, grandparents, siblings and in-laws), anyone else who lives in your household, and any family members who do not live in your household but whose transactions in Company securities are directed by you or are subject to your influence or control, such as parents or children who consult with you before they trade in Company securities (collectively referred to as "Family Members").

You are responsible for the transactions of these other persons and therefore should make them aware of the need to confer with you before they trade in Company securities, and you should treat all such transactions for the purposes of this policy and applicable securities laws as if the transactions were for your own account. This policy does not, however, apply to personal securities transactions of Family Members where the purchase or sale decision is made by a third party not controlled by, influenced by or related to you or your Family Members.

e) Transactions by Entities that You Influence or Control
This Policy applies to any entities that you influence or control, including any corporations, partnerships or trusts (collectively referred to as "Controlled Entities"), and transactions by these Controlled Entities should be treated for the purposes of this Policy and applicable securities laws as if they were for your own account.

Penalties for Violations of the Policy and Insider Trading Laws
The personal consequences to you of illegally trading securities while in possession of material, non-public information can be quite severe. Certain securities laws provide that an individual is subject to possible imprisonment and significant fines. These laws apply to all employees, not just officers and directors. Subject to applicable law, Company employees who violate this policy may also be subject to discipline by the Company, up to and including termination of employment, even if the conduct is not considered illegal.

Transactions under Company Plans
a) 401(k) Plan
Purchases of Company stock under the 401(k) plan based on your previous instructions to regularly deduct money from your paycheck for contribution to the plan **are *not*** affected by the Company's policy. The policy ***does apply***, however, to certain elections if such election will affect holdings in the WEC Energy Group stock funds, including:

- Increasing or decreasing the percentage of your periodic contributions that will be allocated to the WEC Energy Group stock funds,
- Making an intra-plan transfer of an existing account balance into or out of the WEC Energy Group stock funds,
- Borrowing money against your 401(k) plan account if the loan will result in a liquidation of some or all of your WEC Energy Group stock funds balance, and
- Pre-payment of a loan if such pre-payment will result in allocation of loan proceeds to the WEC Energy Group stock funds.

b) Executive and Director Deferred Compensation Plans (EDCP and DDCP)
Purchases in the WEC Energy Group measurement fund resulting from your regular contribution of money to the EDCP or DDCP pursuant to your payroll or other deduction elections **are *not*** affected by the Company's policy. The policy ***does apply***, however, to certain elections you may make under the plan, including:

- An election to increase or decrease the percentage of your periodic contributions that will be allocated to the WEC Energy Group measurement fund,
- An election to make an intra-plan transfer of an existing account balance into or out of the WEC Energy Group measurement fund, and

- A hardship withdrawal if it would result in a liquidation of some or all of your WEC Energy Group measurement fund balance.

c) Stock Purchase and Dividend Reinvestment Plan ("Stock Plus Investment Plan")
The Company's policy does ***not*** apply to shares acquired as a result of the regular reinvestment of cash dividends in Company stock, participation in the Automatic Investment Option, stock splits, stock dividends, or similar distributions within the Stock Plus Investment Plan. The policy ***does apply***, however, to your election to participate in the Stock Plus Investment Plan or change your level of participation in that plan, as well as any voluntary purchases of Company stock resulting from additional contributions you choose to make within the Stock Plus Investment Plan. The policy also applies to your sale of any Company stock, whether the sale is through the Stock Plus Investment Plan or through an independent broker.

d) Stock Option Exercises
The policy ***applies*** to any sale of stock as part of a broker-assisted cashless exercise of an option, or any other market sale of Company securities for the purpose of generating the cash needed to pay the exercise price of an option or tax obligation due on vesting of an equity award. Other than in very limited circumstances, the policy also applies to the exercise of an employee stock option where the employee holds all of the shares acquired upon exercise.

Transactions that are Prohibited

The Company considers it improper and inappropriate to engage in short-term or speculative transactions in the Company's securities. Therefore, it is the Company's policy that the following transactions are entirely prohibited:

a) Short Sales
Short sales of the Company's securities evidence an expectation on the part of the seller that the securities will decline in value, where the securities are sold with the intention of subsequently repurchasing them at a lower price, and therefore signal to the market that the seller has no confidence in the Company or its short- term prospects. In addition, short sales may reduce the seller's incentive to improve the Company's performance. For these reasons, short sales of the Company's securities are prohibited. In addition, Section 16(c) of the Exchange Act prohibits certain officers and directors from engaging in short sales.

b) Publicly Traded Options
A transaction in publicly traded options is, in effect, a bet on the short-term movement of the Company's stock and therefore creates the appearance that such trading is based on inside information. Transactions in options also may focus a person's attention on short-term performance at the expense of the Company's long-term objectives. Accordingly, transactions in puts, calls or other derivative securities, on an exchange or in any other organized market, are prohibited.

c) Hedging Transactions
Certain financial instruments are designed to hedge or offset any potential decrease in the market value of Company securities. Individuals engaged in such transactions may no longer have the same objectives as the Company's other stockholders. Therefore, hedging or monetization transactions (including, but not limited to, prepaid variable forward contracts, equity swaps, collars and exchange funds) are prohibited.

d) Margin Accounts and Pledges
Securities held in a margin account may be sold by the broker without the customer's consent if the customer fails to meet a margin call. Similarly, securities pledged as collateral for a loan may be sold in foreclosure if the borrower defaults on the loan. Because a margin sale or foreclosure sale may occur at a time when the pledgor is aware of material, non-public information or otherwise is not permitted to trade in Company securities, holding Company securities in a margin account or pledging Company securities as collateral for a loan is prohibited.

Post-Termination Transactions

This policy continues to apply to your transactions in Company securities even after termination of employment. If you are in possession of material, non-public information when your employment terminates, you may not trade in Company securities until at least one full trading day after that information has become public or is no longer material.

Additional Restrictions and Guidelines for Directors, Officers, and Certain Other Persons Designated by the General Counsel

a) Mandatory Pre-clearance Procedure

Directors and officers of the Company and any other persons designated by the General Counsel as being subject to the Company's pre-clearance procedures, along with their Family Members and Controlled Entities, may not engage in any transaction involving the Company's securities (including entering into a 10b5-1 trading plan or any gift involving Company securities) without first obtaining pre-clearance of the transaction. A request for pre-clearance should be submitted to the General Counsel or her/his designee using the WEC Pre-Clearance Request Form only after a trading window has opened and at least one business day prior to the date of the proposed transaction. The General Counsel or her/his designee will then determine whether the transaction may proceed and, if so, assist in complying with any reporting requirements. It may take up to one full day to obtain pre-clearance. Clearance of a transaction is only valid for a five-day period (or until the closing of the trading window, whichever is shorter). If the transaction order is not placed within that five-day period, a new request must be submitted using the WEC Pre-Clearance Request Form before conducting the transaction.

b) Trading Window

Except as otherwise explicitly provided in this policy, individuals subject to pre-clearance procedures, as well as their Family Members and Controlled Entities, may only trade in, or enter into a 10b5-1 trading plan involving Company securities, during an open trading window, which generally begins two full trading days after the public release of the Company's quarterly or annual earnings and ends at the close of business on the fourth calendar day in the last month of the respective fiscal quarter. Trading in the Company's securities during the trading window should not be considered a "safe harbor," and all directors, officers and the other designated persons should use good judgement at all time. To review the current trading calendar, click on the link to the Trading Windows.

From time to time, an event may occur that is material to the Company and is known by only a few directors, officers and/or employees. In this case, the General Counsel may impose special blackout periods during which certain persons will be prohibited from trading in Company securities, even though the trading window would otherwise be open. If a special blackout period is imposed, the General Counsel, or her/his designee, will notify affected individuals, who should thereafter not engage in any transaction involving the purchase or sale of the Company's securities and should not disclose to others the fact of such blackout period. If a person subject to the pre-clearance procedures is notified of a special blackout period after receiving approval to trade but before the transaction is placed, such pre-clearance will be considered terminated. Similarly, individuals subject to the pre-clearance procedures may not be pre-cleared during the special blackout period and the Company may not disclose the reason for the special blackout period.

c) Short-term Trading

Section 16(b) of the Securities Exchange Act of 1934 ("Exchange Act") prohibits directors and certain officers from engaging in short-term trading. Therefore, any such director or officer who purchases Company stock in the open market may not sell Company stock during the six months following the purchase and vice versa. This prohibition does not apply to most employee benefit plan acquisitions and dispositions.

d) Rule 10b5-1 Trading Plans

A 10b5-1 trading plan is a contract to purchase or sell securities that is established by a Company insider, prior to effecting any transactions.

Rule 10b5-1 under the Exchange Act provides a defense from insider trading liability under Rule 10b-5. In order to be eligible to rely on this defense, a person must enter into a Rule 10b5-1 plan for transactions in Company securities that meets certain conditions specified in the Rule. If the plan meets the requirements of Rule 10b5-1, Company securities may be purchased or sold without regard to certain insider trading restrictions. A person must enter into a Rule 10b5-1 plan in good faith (*i.e.,* not as part of a scheme or plan to evade the prohibitions of the Rule) and act in good faith with respect to the plan. A Rule 10b5-1 plan must be entered into at a time when the person entering into the plan is not aware of material, non-public information. Once the plan is adopted, the person must not exercise any influence over the amount of securities to be traded or the date of the trade. The plan must either specify the amount, pricing and timing of transactions in advance or delegate discretion on these matters to an independent third party.

A Rule 10b5-1 plan and any modification to a plan must be approved by the Company's General Counsel and meet the requirements of Rule 10b5-1 and these guidelines. Any plan or modification to a plan must be submitted for approval at least one business day prior to the entry into the Rule 10b5-1 plan. No further pre-approval of transactions conducted pursuant to the Rule 10b5-1 plan will be required.

You are not required to seek approval from the Company to terminate a Rule 10b5-1 plan. You should carefully analyze all the relevant facts and circumstances before terminating a Rule 10b5-1 plan, bearing in mind that the SEC has indicated that once the plan is terminated the affirmative defense may not apply to any trades that were made pursuant to the plan if such termination calls into question whether the good faith requirement was met. If you do terminate a Rule 10b5-1 plan, you must notify the Company in writing within one business day of such termination.

The following guidelines apply to all Rule 10b5-1 plans:

- You may only enter into or modify a Rule 10b5-1 plan during an open trading window and only at a time when you are not in possession of material, non-public information.
- You must request pre-clearance before entering into or modifying a Rule 10b5-1 plan.
- If a Rule 10b5-1 plan is terminated early, you must wait at least 30 days before trading in any Company securities outside of the plan.
- If a Rule 10b5-1 plan is terminated early, you must wait until the commencement of the next open trading window before a new plan may be adopted.
- Directors and officers subject to Section 16 may not commence sales under a Rule 10b5-1 plan until the later of 1) 90 days following the date of adoption of the plan or 2) two business days after the filing of the Company's Form 10-Q or 10-K for the quarter in which the plan was adopted. The cooling-off period cannot exceed 120 days.
- Insiders that are not Section 16 reporting persons may not commence sales under a Rule 10b5-1 plan until at least 30 days following the date of adoption of the plan.
- Any modification to the price, amount or timing of purchase or sales under a plan is subject to the applicable cooling-off period.
- You may not enter into any transaction in the same type of Company securities that are the subject of a Rule 10b5-1 plan while such plan is in effect.
- You may not have more than one Rule 10b5-1 plan in effect for any type of Company securities, except that:
  - You may enter into a series of separate contracts using different brokers to execute trades pursuant to a single trading plan if all contracts, taken as a whole, comply with the applicable provisions of Rule 10b5-1. Any modification of one plan will also be a modification to all other plans held with any other broker. You may substitute one broker for another broker as long as any terms with respect to the amount, pricing and timing of transactions remain identical after the substitution.
  - You may maintain two separate plans at the same time if trading under the later-commencing plan does not begin until after all trades under the earlier plan have been completed or expire without execution. However, if the first trading plan is terminated early, the first trade under the later commencing plan must not be scheduled to occur until after the effective cooling-off period following the termination of the earlier plan.
  - You may maintain, in addition to a Rule 10b5-1 plan, a "sell-to-cover" plan to satisfy tax withholding obligations at the time a compensatory award vests.
- You may enter into a plan designed to cover a single-trade if you have not adopted another single-trade plan during the 12 months preceding the adoption of such plan.

SEC Reporting Requirements

Section 16 of the Exchange Act and Rule 144 of the Securities Act of 1933 require directors and executive officers to file reports regarding their ownership of and transactions in Company equity securities with the Securities and Exchange Commission. These reports include:

- Within ten days of election or appointment, a Form 3 stating the insider's beneficial ownership of Company securities;
- Whenever there has been a change in their beneficial ownership (including changes resulting from a gift), an insider must file a Form 4 within two business days unless the transaction qualifies for delayed reporting on Form 5; and
- Within 45 days after the close of the Company's fiscal year, an insider must file a Form 5 to cover any transactions in Company securities which were eligible for delayed reporting (and not earlier reported on Form 4) and transactions that should have been but were not reported on Form 4.

Covered Persons

The filing requirements apply to all Section 16 reporting persons.

Covered Transactions

In addition to purchases and sales, the two-day reporting requirement applies to most changes in ownership, including stock and option grants, as well as certain other transfers. The reporting requirement also applies to transactions in Company stock by Family Members and Controlled Entities.

Automatic Dividend Reinvestments
Generally, directors and executive officers are not required to report purchases of Company stock as a result of the automatic reinvestment of dividends. However, when a transaction occurs in which a Form 4 filing is required, the adjusted ownership total that is reported must be inclusive of those purchases.

e) Broker Interface Procedures
The accelerated reporting of transactions requires tight interface with brokers handling transactions for our directors and executive officers. A knowledgeable, alert broker can act as a gatekeeper, helping ensure compliance with the pre-clearance procedures and helping prevent inadvertent violations. We have established a coordinated procedure with the Morgan Stanley Smith Barney (MSSB) brokerage firm. As a result, directors and executive officers are encouraged to use MSSB as their broker.

Whether you choose to utilize MSSB or your own broker, we will require that you and your broker comply with the following requirements regarding the broker handling your transaction in Company stock:

i) That your broker has put a restriction on your accounts so that the broker may not transact in Company securities without your knowledge and approval.

ii) Not to enter any order (except for orders under pre-approved Rule 10b5-1 plans) without:
- First verifying with the Company that your transaction was pre-cleared; and
- Complying with the brokerage firm's compliance procedures (e.g., Rule 144).

iii) To report immediately to the Company the details of every transaction involving Company stock, including gifts, transfers, pledges, and all 10b5-1 transactions, as well as changes in ownership as a result of automatic dividend reinvestments.

The General Counsel or her/his designee can assist in making the necessary arrangements to establish a coordinated procedure with your broker.

Compliance and Certification
a) Individual Responsibility
Every director, officer and other employee has the individual responsibility to comply with this Policy and applicable law. Such individuals may, from time to time, have to forego a proposed transaction in the Company's securities even if he or she planned to make the transaction before learning of the material, non- public information and even though the individual believes he or she may suffer an economic loss or forego anticipated profit by waiting.

b) Reporting Violations/Seeking Advice
- If you receive material, non-public information that you are not authorized to receive or that you do not legitimately need to know to perform your employment responsibilities, you may not share it with anyone.
- If you receive confidential information and are unsure if it is within the definition of material, non-public information or whether its release might be contrary to a fiduciary or other duty or obligation, you may not share it with anyone.
- You should refer suspected violations of this policy to the Compliance Officer.

Any person who has a question about this policy or its application to any proposed transaction may obtain additional guidance from the General Counsel. Consulting your colleagues can have the effect of exacerbating the problem.

c) Certifications
Directors, officers and certain employees shall periodically be required to submit certification of their training and compliance with this policy.

Related Resources
Code of Business Conduct
Financial Communication Disclosure
Information Security Policy
Trading Windows
Pre-Clearance Trading Form

WEC ENERGY GROUP, INC.
PRE-CLEARANCE REQUEST FORM

Name: ____

Is this request for a pre-clearance extension? ☐ Yes ☐ No

Transaction Type (Please check all the boxes that are applicable)

☐ Exercise and sell options

☐ Sell stock on open market

☐ Modify dividend reinvestment

☐ Gift or charitable donation

☐ Set-up or modify 10b5-1 Plan

☐ 401(k) transaction* (check applicable boxes)

- ☐ Increase/decrease allocation to WEC Energy Group stock fun
- ☐ 401(k) loan transaction
- ☐ Intra-plan transfer into/out of WEC Energy Group stock fund

☐ Exercise and hold options

☐ Purchase stock on open market

☐ Contribution to trust or charitable account

☐ Transfer due to Domestic Relations Order

☐ Modify Executive Deferred Compensation Plan (EDCP) allocations or contributions (check applicable boxes)

- ☐ Increase/decrease allocation to WEC Energy Group measurement fund
- ☐ Intra-plan transfer into/out of WEC Energy Group measurement fund
- ☐ Hardship withdrawal that impacts your WEC Energy Group measurement fund balance

* You do not need to seek pre-clearance if you are changing the % of your compensation (e.g., 3% to 4%) being deducted for future contributions to your 401(k) account, unless you are starting, modifying or terminating an allocation to the WEC Energy Group stock funds.

Number of options/shares or monetary value of the transaction(s). In the case of options, please indicate the grand date(s):

If setting up a 10b5-1 Plan, please describe the transaction(s) to be covered by the plan. If the plan will cover options, please indicate the grant date(s) and number of options

☐ Yes ☐ No Are you subject to a current blackout restriction due to the creation or termination of a 10b5-1 plan?

☐ Yes ☐ No Do you possess any material non-public information?

Please describe the transaction(s) in your own words:

By signing below, I confirm that to the best of my knowledge, this information is correct.

Signature Date

Please email your request to the Corporate Affairs Department (ca-dept@wecenergygroup.com). It may take up to 24-hours to obtain pre-clearance. Clearance of a transaction is valid for a five-day period (or until the trading window closes, whichever occurs first). If the transaction order is not placed within that five-day period, you must seek a pre-clearance extension.

WEC ENERGY GROUP, INC.
SUBSIDIARIES AS OF DECEMBER 31, 2025

The following table includes the subsidiaries of WEC Energy Group, a diversified holding company incorporated in the state of Wisconsin, as well as the percent of ownership, as of December 31, 2025:

Subsidiary *	State of Incorporation or Organization	Percent Ownership
ATC Holding LLC	Wisconsin	100%
American Transmission Company LLC	Wisconsin	60.34%
ATC Development Manager, Inc.	Delaware	74.73%
ATC Holdco LLC	Delaware	75.17%
ATC Management Inc.	Wisconsin	60.32%
Bluewater Natural Gas Holding, LLC	Delaware	100%
BGS Kimball Gas Storage, LLC	Delaware	100%
Bluewater Gas Storage, LLC	Delaware	100%
Integrys Holding, Inc.	Wisconsin	100%
Michigan Gas Utilities Corporation	Delaware	100%
Minnesota Energy Resources Corporation	Delaware	100%
Peoples Energy, LLC	Delaware	100%
North Shore Gas Company	Illinois	100%
The Peoples Gas Light and Coke Company	Illinois	100%
Wisconsin Public Service Corporation	Wisconsin	100%
Wisconsin River Power Company	Wisconsin	50%
Upper Michigan Energy Resources Corporation	Michigan	100%
W.E. Power, LLC	Wisconsin	100%
Elm Road Generating Station Supercritical, LLC	Wisconsin	100%
Elm Road Services, LLC	Wisconsin	100%
Port Washington Generating Station, LLC	Wisconsin	100%
WEC Business Services LLC	Delaware	100%
WEC Infrastructure LLC	Delaware	100%
Delilah Solar Holdings LLC	Delaware	90%
HSE3 Holdings LLC	Delaware	90%
Samson OpCo Holdings LLC	Delaware	90%
WEC Infrastructure Wind Holding I LLC	Delaware	100%
Bishop Hill Energy III Holdings LLC	Delaware	90%
Blooming Grove Wind Energy Center Holdings LLC	Delaware	90%
Coyote Ridge Wind, LLC	Oregon	82.61%
Upstream Wind Energy Holdings LLC	Delaware	90%
WEC Infrastructure Wind Holding II LLC	Delaware	100%
Jayhawk Wind, LLC	Delaware	90%
Tatanka Ridge Wind, LLC	Delaware	85.68%
WEC Infrastructure Energy Holding III LLC	Delaware	100%
Maple Flats Holding LLC	Delaware	90%
Sapphire Sky Wind Energy Holdings LLC	Delaware	90%
Thunderhead Wind Energy Holdings LLC	Delaware	90%
WEC Investments, LLC	Delaware	100%
Wisconsin Electric Power Company	Wisconsin	100%
Wisconsin Gas LLC	Wisconsin	100%
Wispark LLC	Wisconsin	100%

* Omits the names of certain subsidiaries, which if considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" as of December 31, 2025. Indirectly owned subsidiaries are listed under the subsidiaries through which WEC Energy Group holds ownership.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-281253 and 333-275065 on Form S-3 and Registration Statement Nos. 333-213589, 333-177572, and 333-161151 on Form S-8 of our reports dated February 20, 2026, relating to the consolidated financial statements and financial statement schedules of WEC Energy Group, Inc. and the effectiveness of WEC Energy Group, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of WEC Energy Group, Inc. for the year ended December 31, 2025.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 20, 2026

Exhibit 31.1

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Scott J. Lauber, certify that:

1. I have reviewed this Annual Report on Form 10-K of WEC Energy Group, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2026

/s/ SCOTT J. LAUBER

Scott J. Lauber
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Xia Liu, certify that:

1. I have reviewed this Annual Report on Form 10-K of WEC Energy Group, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2026

/s/ XIA LIU

Xia Liu
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of WEC Energy Group, Inc. (the "Company") on Form 10-K for the period ended December 31, 2025, as filed with the Securities and Exchange Commission on February 20, 2026 (the "Report"), I, Scott J. Lauber, President and Chief Executive Officer, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ SCOTT J. LAUBER

Scott J. Lauber
President and Chief Executive Officer
February 20, 2026

Exhibit 32.2

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of WEC Energy Group, Inc. (the "Company") on Form 10-K for the period ended December 31, 2025, as filed with the Securities and Exchange Commission on February 20, 2026 (the "Report"), I, Xia Liu, Executive Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ XIA LIU

Xia Liu
Executive Vice President and Chief Financial Officer
February 20, 2026