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, 2021

**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.<br>(A Wisconsin Corporation)<br>231 West Michigan Street<br>P.O. Box 1331<br>Milwaukee, WI 53201<br>(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. ☒

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 $28.1 billion based upon the reported closing price of such securities as of June 30, 2021.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2022):

Common Stock, $.01 par value, 315,434,531 shares outstanding

Documents incorporated by reference:

Portions of WEC Energy Group, Inc.'s Definitive Proxy Statement on Schedule 14A for its Annual Meeting of Shareholders, to be held on May 5, 2022, are incorporated by reference into Part III hereof.

**WEC ENERGY GROUP, INC.**
**ANNUAL REPORT ON FORM 10-K**
**For the Year Ended December 31, 2021**
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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 |
| Integrys | Integrys Holding, Inc. |
| Jayhawk | Jayhawk Wind, 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 |
| Tatanka Ridge | Tatanka Ridge Wind, 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 Wind Holding I | WEC Infrastructure Wind Holding I 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 |
| EPA | United States Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| ICC | Illinois Commerce Commission |
| IDNR | Illinois Department of Natural Resources |
| IEPA | Illinois Environmental Protection Agency |
| 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 |
| 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**

| | |
|---|---|
| ACE | Affordable Clean Energy |
| Act 141 | 2005 Wisconsin Act 141 |
| BATW | Bottom Ash Transport Water |
| BTA | Best Technology Available |
| CAA | Clean Air Act |
| $CO_2$ | Carbon Dioxide |
| ELG | Steam Electric Effluent Limitation Guidelines |
| FGD | Flue Gas Desulfurization |
| GHG | Greenhouse Gas |
| GMZ | Groundwater Management Zone |
| NAAQS | National Ambient Air Quality Standards |
| NOV | Notice of Violation |
| NOx | Nitrogen Oxide |
| PCB | Polychlorinated Biphenyl |
| $SO_2$ | Sulfur Dioxide |
| VN | Violation Notice |
| WOTUS | Waters of the United States |

**Measurements**

| | |
|---|---|
| Bcf | Billion Cubic Feet |
| Dth | Dekatherm |
| MDth | One Thousand Dekatherms |
| MW | Megawatt |
| MWh | Megawatt-hour |

**Other Terms and Abbreviations**

| | |
|---|---|
| 2007 Junior Notes | WEC Energy Group, Inc.'s 2007 Junior Subordinated Notes Due 2067 |
| 2013 Junior Notes | Integrys Holding, Inc.'s 6.00% Junior Notes Due August 1, 2073 |
| AG | Attorney General |
| AMI | Advanced Metering Infrastructure |
| ARR | Auction Revenue Right |
| Badger Hollow I | Badger Hollow Solar Park I |
| Badger Hollow II | Badger Hollow Solar Park II |
| Blue Sky | Blue Sky Green Field Wind Park |
| CDC | Centers for Disease Control and Prevention |
| CFR | Code of Federal Regulations |
| Compensation Committee | Compensation Committee of the Board of Directors of WEC Energy Group, Inc. |
| COVID-19 | Coronavirus Disease – 2019 |
| Crane Creek | Crane Creek Wind Park |
| D.C. Circuit Court of Appeals | United States Court of Appeals for the District of Columbia Circuit |
| ERGS | Elm Road Generating Station |
| ER 1 | Elm Road Generating Station Unit 1 |
| ER 2 | Elm Road Generating Station Unit 2 |
| ESG Progress Plan | WEC Energy Group's Capital Investment Plan for Efficiency, Sustainability, and Growth for 2021-2025 |
| ETB | Environmental Trust Bond |
| EV | Electric Vehicle |
| Exchange Act | Securities Exchange Act of 1934, as amended |

| | |
|---|---|
| Executive Order 13990 | Executive Order 13990 of January 20, 2021 - Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis |
| Forward Wind | Forward Wind Energy Center |
| FTR | Financial Transmission Right |
| GCRM | Gas Cost Recovery Mechanism |
| GUIC | Gas Utility Infrastructure Costs |
| Holding Company Act | Wisconsin Utility Holding Company Act |
| ITC | Investment Tax Credit |
| LIBOR | London Interbank Offered Rate |
| LMP | Locational Marginal Price |
| LNG | Liquefied Natural Gas |
| MISO | Midcontinent Independent System Operator, Inc. |
| MISO Energy Markets | MISO Energy and Operating Reserves Market |
| NYMEX | New York Mercantile Exchange |
| OCPP | Oak Creek Power Plant |
| OC 5 | Oak Creek Power Plant Unit 5 |
| OC 7 | Oak Creek Power Plant Unit 7 |
| OC 8 | Oak Creek Power Plant Unit 8 |
| Omnibus Stock Incentive Plan | WEC Energy Group Omnibus Stock Incentive Plan, Amended and Restated, Effective as of May 6, 2021 |
| PIPP | Presque Isle Power Plant |
| Point Beach | Point Beach Nuclear Power Plant |
| PPA | Power Purchase Agreement |
| PSB | Public Service Building |
| PTC | Production Tax Credit |
| PUHCA 2005 | Public Utility Holding Company Act of 2005 |
| 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 |
| RCC | Replacement Capital Covenant (dated May 11, 2007) |
| REC | Renewable Energy Certificate |
| RICE | Reciprocating Internal Combustion Engine |
| RNG | Renewable Natural Gas |
| ROE | Return on Equity |
| RTO | Regional Transmission Organization |
| Sapphire Sky | Sapphire Sky Wind Energy LLC |
| SMP | Safety Modernization Program |
| SPC | COVID-19 Special Purpose Charge |
| SSR | System Support Resource |
| Supreme Court | United States Supreme Court |
| Tax Legislation | Tax Cuts and Jobs Act of 2017 |
| Thunderhead | Thunderhead Wind Energy LLC |
| Tilden | Tilden Mining Company |
| TPTFA | Third-Party Transaction Fee Adjustment |
| Two Creeks | Two Creeks Solar Park |
| VAPP | Valley Power Plant |
| West Riverside | West Riverside Energy Center |
| Whitewater | Whitewater Cogeneration Facility |
| WRO | Withhold Release Order |

## 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 ESG Progress 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 operations such as catastrophic weather-related damage, including climate change, environmental incidents, unplanned facility outages and repairs and maintenance, 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, including climate change, changes in economic conditions, customer growth and declines, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers;

- 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 health pandemics, including the COVID-19 pandemic, on our business functions, financial condition, liquidity, and results of operations;

- The impact of recent and future federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, the expiration and non-renewal of the QIP rider, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, and tax laws, including those that affect our ability to use PTCs and ITCs;

- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards, the enforcement of these laws and regulations, changes in 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 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 supply chain disruptions, future inflation, and other factors;

- Factors affecting the implementation of our $CO_2$ emission and/or methane emission reduction goals and opportunities and actions related to those goals, including related regulatory decisions, the cost of materials, supplies, and labor, technology advances, the feasibility of competing generation projects, and our ability to execute our capital plan;

- The financial and operational feasibility of taking more aggressive action to further reduce GHG emissions in order to limit future global temperature increases;

- 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;

- 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;

- Changes in the method of determining LIBOR or the replacement of LIBOR with an alternative reference rate;

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

- The direct or indirect effect on our business resulting from terrorist attacks and cyber security 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 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 related to our non-utility renewable energy facilities, including unfavorable weather, the ability to replace expiring long-term PPAs under acceptable terms, and the availability of reliable interconnection and electricity grids;

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

- Potential business strategies to acquire and dispose of assets or businesses, 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 wind 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, 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, 2021, 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

For the periods presented in this Annual Report on Form 10-K, our electric utility operations included 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. WE also served an iron ore mine customer, Tilden, in the Upper Peninsula of Michigan, through March 31, 2019 when Tilden became a customer of UMERC. In 2021, WE's consolidated revenues also include securitization revenues collected from customers as servicer of environmental control property owned by its subsidiary WEPCo Environmental Trust. For more information on WEPCo Environmental Trust, see Note 23, Variable Interest Entities.

- WPS generates and distributes electric energy to customers located in northeastern and central Wisconsin.
- UMERC generates and distributes electric energy to customers located in the Upper Peninsula of Michigan. UMERC began generating electricity when its new natural gas-fired generation achieved commercial operation on March 31, 2019.

### *Operating Revenues*

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2021, 2020, and 2019, see 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 2021, retail revenues accounted for 91.8% of total electric operating revenues, wholesale revenues accounted for 3.5% of total electric operating revenues, and resale revenues accounted for 3.6% 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.

Our electric utilities buy and sell wholesale 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, based on our customers' needs. We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers. For more information, see E. Regulation.

The majority of our sales for resale are sold into 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 costs of sales derived from these opportunity sales.

**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 2021, as compared with 2020, due to a partial recovery from the impact of the first year of the COVID-19 pandemic. We currently forecast retail electric sales volumes, excluding the Tilden mine located in the Upper Peninsula of Michigan, to grow between 0.5% and 1.0% over the next five years, assuming normal weather. Electric peak demand is expected to be flat over the next five years.

### *Customers*

| *(in thousands)* | Year Ended December 31 2021 | 2020 | 2019 |
|---|---|---|---|
| **Electric customers – end of year** | | | |
| Residential | **1,460.4** | 1,455.7 | 1,446.0 |
| Small commercial and industrial | **175.8** | 175.8 | 174.6 |
| Large commercial and industrial | **0.8** | 0.8 | 0.9 |
| Wholesale and other | **1.6** | 3.0 | 2.7 |
| **Total electric customers – end of year** | **1,638.6** | 1,635.3 | 1,624.2 |
| | | | |
| **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, metal mining, paper, governmental, health services, food products, and real estate.

### *Electric Generation and Supply Mix*

Our electric supply strategy is to provide our customers with energy from plants using a diverse fuel mix that is expected to balance 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 power plants 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. All options, including owned generation resources and purchased power opportunities, are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements.

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 2022:

| | Estimate [1] 2022 | Actual 2021 | 2020 | 2019 |
|---|---|---|---|---|
| **Company-owned generation units:** | | | | |
| Coal [2] | 33.3 % | **35.5 %** | 31.1 % | 36.3 % |
| Natural gas: | | | | |
| Combined cycle | 18.9 % | **24.6 %** | 27.8 % | 26.8 % |
| Steam turbine | 0.7 % | **0.8 %** | 1.0 % | 0.8 % |
| Natural gas/oil peaking units | 1.8 % | **3.1 %** | 2.4 % | 0.9 % |
| Renewables [3] | 5.9 % | **4.8 %** | 5.3 % | 4.4 % |
| Total company-owned generation units | 60.6 % | **68.8 %** | 67.6 % | 69.2 % |
| **Power purchase contracts:** | | | | |
| Nuclear | 21.1 % | **19.0 %** | 19.5 % | 19.8 % |
| Natural gas | 1.3 % | **1.9 %** | 1.9 % | 1.8 % |
| Renewables [3] | 2.4 % | **1.9 %** | 1.9 % | 2.0 % |
| Other | — % | **0.1 %** | 1.7 % | 1.8 % |
| Total power purchase contracts | 24.8 % | **22.9 %** | 25.0 % | 25.4 % |
| Purchased power from MISO | 14.6 % | **8.3 %** | 7.4 % | 5.4 % |
| Total purchased power | 39.4 % | **31.2 %** | 32.4 % | 30.8 % |
| **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 2021 NYMEX.

(2) In 2021, we used more coal generation for electric supply, compared with 2020. Even though coal costs also increased in 2021, it was still more cost effective than natural gas due to increased natural gas prices in 2021. We still anticipate using less coal in the future as we plan to achieve

our emission reduction goals through the addition of renewable generation and eventual closure of existing coal generating facilities if approved by regulators.

(3) Includes hydroelectric, biomass, solar, and wind generation.

### *Electric Generation Facilities*

Our generation portfolio is a mix of energy resources having different operating characteristics and fuel sources designed to balance providing energy that is stable, reliable, and affordable with environmental stewardship. We own 7,751 MW of generation capacity, including wholly owned and jointly owned facilities. We Power's generating units are also included in the generation capacity. Our facilities include coal-fired plants, natural gas-fired plants, and renewable generation. 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.

In November 2021, we added to our electrical generation portfolio when Badger Hollow I, a new utility scale solar facility with a 150 MW nameplate capacity in Iowa County, Wisconsin, achieved commercial operation. WPS owns 100 MW of Badger Hollow I.

## Creating a Sustainable Future

Our ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fired generation. When taken together, the retirements and new investments should better balance our supply with our demand, while maintaining reliable, affordable energy for our customers. The retirements will contribute to meeting our goals to reduce $CO_2$ emissions from our electric generation.

In May 2021, we announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by 2025 and by 80% by 2030, both from a 2005 baseline. We expect to achieve these goals by making operating refinements, retiring less efficient generating units, and executing our capital plan. Over the longer term, the target for our generation fleet is net-zero $CO_2$ emissions by 2050.

As part of our path toward these goals, we are exploring co-firing with natural gas at our ERGS coal-fired units. By the end of 2030, we expect our use of coal will account for less than 5% of the power we supply to our customers, and we believe we will be in a position to eliminate coal as an energy source by 2035.

We already have retired more than 1,800 MW of coal-fired generation since the beginning of 2018, which included the 2019 retirement of the PIPP as well as the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating units. See Note 6, Regulatory Assets and Liabilities, for more information related to these power plant retirements. Through our ESG Progress Plan, we expect to retire approximately 1,600 MW of additional fossil-fueled generation by 2025, which includes the planned retirements in 2023-2024 of OCPP Units 5-8 and the jointly-owned Columbia Units 1-2.

In August 2021, the PSCW approved pilot programs for WE and WPS to install and maintain EV charging equipment for customers at their homes or businesses. The programs provide direct benefits to customers by removing cost barriers associated with installing EV equipment. In October 2021, subject to the receipt of any necessary regulatory approvals, we pledged to expand the EV charging network within the service territories of our electric utilities. In doing so, we joined a coalition of utility companies in a unified effort to make EV charging convenient and widely available throughout the Midwest. The coalition we joined is planning to help build and grow EV charging corridors, enabling the general public to safely and efficiently charge their vehicles.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Corporate Developments for more information on the ESG Progress Plan.

#### 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 maintain 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.

In December 2018, WE received approval from the PSCW for the Dedicated Renewable Energy Resource pilot program, a program for large commercial and industrial customers who wish to access renewable resources that WE would operate, adding up to 150 MW of renewables to WE's portfolio, and helping these larger customers meet their sustainability and renewable energy goals.

***Wind***

In January 2022, WPS, along with an unaffiliated utility, received approval from the PSCW to acquire the Red Barn Wind Park, a utility-scale wind-powered electric generating facility. The project will be located in Grant County, Wisconsin and once constructed, WPS will own 82 MW of this project. Construction of the project is expected to be completed by the end of 2022.

In September 2021, WE and WPS received approval to accelerate capital investments to repower major components of Blue Sky and Crane Creek wind parks, which are expected to be completed by the end of 2022.

***Solar and Battery Storage***

As part of our commitment to invest in zero-carbon generation, we have filed applications with the PSCW for approval to invest in 675 MW of utility-scale solar and 316 MW of battery storage within our Wisconsin segment, including the following:

- In April 2021, WE and WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire the Koshkonong Solar-Battery Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Dane County, Wisconsin and once constructed, WE and WPS will collectively own 270 MW of solar generation and 149 MW of battery storage of this project. If approved, construction of the project is expected to be completed by the second quarter of 2024.

- In March 2021, WE and WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire and construct the Darien Solar-Battery Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Rock and Walworth counties, Wisconsin and once constructed, WE and WPS will collectively own 225 MW of solar generation and 68 MW of battery storage of this project. If approved, construction of the project is expected to be completed by the end of 2023.

- In February 2021, WE and WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire and construct the Paris Solar-Battery Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Kenosha County, Wisconsin and once constructed, WE and WPS will collectively own 180 MW of solar generation and 99 MW of battery storage of this project. If approved, construction of the project is expected to be completed by the end of 2023.

We have received approval from the PSCW to invest in 135 MW of utility-scale solar projects within our Wisconsin segment, including the following:

- In August 2019, WE partnered with an unaffiliated utility to construct a solar project, Badger Hollow II, that will be located in Iowa County, Wisconsin and is expected to enter commercial operation in the first quarter of 2023. Once constructed, WE will own 100 MW of this project.

- In December 2018, WE received approval from the PSCW for the Solar Now pilot program, which is expected to add 35 MW of solar generation to WE's portfolio, allowing non-profit and government entities, as well as commercial and industrial customers, to site utility owned solar arrays on their property. Under this program, WE has energized 21 Solar Now projects and currently has another three under construction, together totaling more than 27 MW.

**Natural Gas-Fired Generation**

We have filed applications with the PSCW for approval to invest in 464.5 MW of natural gas-fired generation within our Wisconsin segment, including the following:

- In January 2022, WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire a portion of West Riverside's nameplate capacity. WPS is also requesting approval to assign the option to purchase part of West Riverside to WE. If approved, WPS or WE would acquire 100 MW of capacity, in the first of two potential option exercises. West Riverside is a new, combined-cycle natural gas plant recently completed by an unaffiliated utility in Rock County, Wisconsin. If approved, the transaction is expected to close in the second quarter of 2023.

- In December 2021, WE and WPS filed an application with the PSCW for approval to acquire Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electrical generation facility in Whitewater, Wisconsin. If approved, the transaction is expected to close in January 2023.

- In April 2021, WE and WPS filed an application with the PSCW for the approval to construct a 128 MW natural gas-fired generation facility at WPS's existing Weston power plant site in northern Wisconsin. The new facility will consist of seven reciprocating internal combustion engines. If approved, construction of the project is expected to be completed by the end of 2023.

### *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 has an 18.3% installed capacity reserve margin requirement for the planning year from June 1, 2021, through May 31, 2022, and a 17.9% installed capacity reserve margin requirement for the planning year from June 1, 2022, through May 31, 2023. MISO's short-term reserve margin requirements experience year-to-year 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 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, 2022, through May 31, 2023. 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:

| | 2021 | 2020 | 2019 |
|---|---|---|---|
| Coal | **$ 21.06** | $ 20.16 | $ 22.77 |
| Natural gas combined cycle | **24.55** | 16.24 | 19.55 |
| Natural gas/oil peaking units | **76.96** | 39.37 | 51.80 |
| Biomass | **86.24** | 130.76 | 102.99 |
| Purchased power | **50.88** | 43.50 | 42.53 |

WE and WPS purchase coal under long-term contracts, which helps with price stability. In the past, coal and associated transportation services were exposed to volatility in pricing due to changing domestic and world-wide demand for coal and diesel fuel. WE and WPS have PSCW approval for a hedging program to moderate this volatility exposure. This program allows them to hedge, over a 36-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 moderate volatility related to natural gas price risk. This program allows them to hedge, over a 36-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 2022, approximately 99% of our total projected coal requirements of 7.5 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 |
|---|---|
| 2022 | 7,373 |
| 2023 | 4,800 |
| 2024 | 2,250 |

**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.

### *Power Purchase Commitments*

We enter into short- and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. Our power purchase commitments with unaffiliated parties consist of 1,133 MW per year for 2022 through 2026, which exclude planning capacity purchases. Each of these amounts include 1,033 MW per year related to a long-term PPA for electricity generated by Point Beach. Through our ESG Progress Plan, we retired some of our older, less efficient coal-fired generation in 2018 and 2019. To procure additional planning capacity, we purchased 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, commercial and industrial, and transportation customers. Major industries served include real estate, restaurants, food products, governmental, 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, 2021, 2020, and 2019, see 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 2021 as compared to 2020 due to the impact of a full year of the COVID-19 pandemic in 2021 and higher natural gas prices. We currently forecast retail natural gas delivery volumes to grow at a rate between 0.7% and 1.0% over the next five years, assuming normal weather.

### *Customers*

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in thousands)*** | **2021** | **2020** | **2019** |
| **Customers – end of year** | | | |
| Residential | **1,353.2** | 1,346.9 | 1,336.6 |
| Commercial and industrial | **131.8** | 132.3 | 131.5 |
| Transport | **3.5** | 3.4 | 3.2 |
| **Total customers** | **1,488.5** | 1,482.6 | 1,471.3 |

### *Natural Gas Supply, Pipeline Capacity and Storage*

We have been able to meet our contractual obligations with both our suppliers and our customers. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

**Pipeline Capacity and Storage**

The interstate pipelines serving Wisconsin access supply from natural gas producing areas in the Southern and Eastern United States, along with western Canada. We have contracted for long-term firm capacity from a number of these sources. 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 95% 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 hold daily transportation and storage capacity entitlements with interstate pipeline companies as well as other service providers under varied-length long-term contracts.

Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. Peak or near-peak demand generally occurs only a few times each year. 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 and propane facilities located within our distribution system. These facilities are typically utilized during extreme demand conditions to ensure reliable supply to our customers. In addition to their existing facilities, WE and WG each plan to construct an additional LNG facility. Each facility would provide approximately one Bcf of natural gas supply to meet anticipated peak demand without requiring the construction of additional interstate pipeline capacity. Commercial operation of the WE and WG LNG facilities are targeted for the end of 2023 and 2024, respectively.

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 35.2 million therms for the 2021 through 2022 heating season. Our Wisconsin segment natural gas utilities' peak daily send-out during 2021 was 23.9 million therms on February 14, 2021.

**Natural Gas Supply**

We have contracts with suppliers for natural gas acquired in the Chicago, Illinois market hub and in some of the producing areas discussed above. The pricing of the term contracts is based upon first of the month indices.

We expect to continue to make natural gas purchases in the spot market as price and other circumstances dictate. We have supply relationships with a number of sellers from whom we purchase natural gas in the spot market.

**Hedging Natural Gas Supply Prices**

WE, WPS, and WG have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand using a mix of NYMEX-based natural gas options and futures contracts. 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.

To the extent that opportunities develop and physical supply operating plans are supportive, WE, WPS, and WG also have PSCW approval to utilize NYMEX-based natural gas derivatives to capture favorable forward-market price differentials. These approvals provide for 100% of the related proceeds to accrue to these companies' 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, commercial and industrial, and transportation customers. 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.

### Illinois Utilities Operating Statistics

#### *Operating Revenues*

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2021, 2020, and 2019, see Note 4, Operating Revenues.

### *Customers*

| (in thousands) | Year Ended December 31 2021 | 2020 | 2019 |
|---|---|---|---|
| **Customers – end of year** | | | |
| Residential | **904.5** | 895.9 | 870.6 |
| Commercial and industrial | **71.5** | 71.4 | 71.8 |
| Transport | **68.3** | 74.8 | 88.7 |
| **Total customers** | **1,044.3** | 1,042.1 | 1,031.1 |

### *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 with safe, reliable natural gas supplies at the best value. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

**Pipeline Capacity and Storage**

We contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having multiple pipelines that serve our natural gas service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for our Illinois utilities when negotiating new agreements for transportation and storage services.

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.

Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. Peak or near-peak demand generally occurs only a few times each year. 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.

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 25.9 million therms for the 2021 through 2022 heating season. Our Illinois utilities' peak daily send-out during 2021 was 18.0 million therms on February 14, 2021.

**Natural Gas Supply**

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, contracted and owned 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**

Our Illinois 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. Their hedging programs are reviewed by the ICC as part of the annual purchased gas adjustment reconciliation. They hedge between 25% and 50% of natural gas purchases, with a target of 37.5%.

### Natural Gas System Modernization Program

PGL is continuing work on the SMP, a project to replace approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure that began in 2011. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023. For information on regulatory proceedings related to the SMP, see Note 26, Regulatory Environment.

## 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, commercial and industrial, and transportation customers. Major industries served include wholesale distributors, education, non-profits, metals manufacturing, and real estate. 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 for this segment.

### Other States Utilities Operating Statistics

### Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2021, 2020, and 2019, see Note 4, Operating Revenues.

### Customers

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in thousands)* | **2021** | **2020** | **2019** |
| **Customers – end of year** | | | |
| Residential | **370.1** | 365.7 | 360.8 |
| Commercial and industrial | **35.5** | 35.1 | 35.0 |
| Transport | **23.6** | 24.4 | 24.7 |
| **Total customers** | **429.2** | 425.2 | 420.5 |

### 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 with safe, reliable natural gas supplies at the best value. 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.

Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. Peak or near-peak demand generally occurs only a few times each year. 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.

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 9.3 million therms for the 2021 through 2022 heating season. Our other states utilities' peak daily send-out during 2021 was 7.3 million therms on February 7, 2021.

**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 2021, our generating plants performed as expected during the warmest periods of the summer, and all power purchase commitments under firm contract were received. During this period, our electric utilities did not require public appeals for conservation, and they did not interrupt or curtail service to non-firm customers who participate in load management programs. WPS 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, interruptible customers 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. 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 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.

## Environmental Goals

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

We continue to reduce methane emissions by improving our natural gas distribution system. We set a target across our natural gas distribution operations to achieve net-zero methane emissions by the end of 2030. We plan to achieve our net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of RNG throughout our utility systems. We recently signed our first contract for RNG for our natural gas distribution business, which will be transporting the output of a local dairy farm onto our gas distribution system. The RNG supplied will directly replace higher-emission methane from natural gas that would have entered our pipes. This one contract represents 25 percent of our 2030 goal for methane reduction. We expect to have RNG flowing to our distribution network by the end of 2022.

## 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 is 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, 2021, our ownership interest in ATC was approximately 60%. In addition, as of December 31, 2021, 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 has issued orders 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 wind 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 MW 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 MW, 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 and the PWGS units have 25-year leases).

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, provides natural gas storage and hub services for our Wisconsin natural gas utilities. WE, WPS, and WG have entered into long-term service agreements for natural gas storage with a wholly owned subsidiary of Bluewater.

## WEC Infrastructure LLC

At December 31, 2021, our non-utility energy infrastructure segment included WECI's ownership interests in the wind 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 | 80.0 % | December 2019 |
| Blooming Grove | 90.0 % | December 2020 |
| Tatanka Ridge | 85.0 % | January 2021 |
| Jayhawk | 90.0 % | December 2021 |

Bishop Hill III, Coyote Ridge, Blooming Grove, Tatanka Ridge, and Jayhawk have offtake agreements with creditworthy third parties for the sale of all the energy they produce. In addition, Upstream's revenue is substantially fixed over a 10-year period through an agreement with a creditworthy third party. Under the Tax Legislation, all of these investments qualify for PTCs. WECI is entitled to the tax benefits of Upstream, Bishop Hill III, and Blooming Grove 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 equal to its ownership interests. WECI recognizes PTCs as power is generated over 10 years.

In August 2019, WECI signed an agreement to acquire an 80% ownership interest in Thunderhead, a 300 MW wind generating facility under construction in Nebraska. In February 2020, WECI amended this agreement to acquire an additional 10% ownership interest in Thunderhead. The project has an offtake agreement for all of the energy to be produced by the facility for 12 years. WECI's investment in Thunderhead is expected to qualify for PTCs.

In June 2021, WECI signed an agreement to acquire a 90% ownership interest in Sapphire Sky, a 250 MW wind generating facility under construction in McLean County, Illinois. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 12 years. WECI's investment in Sapphire Sky is expected to qualify for PTCs.

See Note 2, Acquisitions, for more information on these wind generating facilities.

### *Seasonality*

The electricity produced and revenues generated by our 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.

## 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. 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 IDNR; the IEPA; 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:

| | 2021 | | 2020 | | 2019 | |
|---|---|---|---|---|---|---|
| *(in millions)* | **Amount** | **Percent** | **Amount** | **Percent** | **Amount** | **Percent** |
| **Electric** | | | | | | |
| Wisconsin | **$ 4,035.1** | **88.9 %** | $ 3,823.7 | 89.4 % | $ 3,807.4 | 88.2 % |
| Michigan | **166.7** | **3.7 %** | 127.2 | 3.0 % | 142.6 | 3.3 % |
| FERC – Wholesale | **336.8** | **7.4 %** | 323.1 | 7.6 % | 367.6 | 8.5 % |
| Total electric | **4,538.6** | **100.0 %** | 4,274.0 | 100.0 % | 4,317.6 | 100.0 % |
| | | | | | | |
| **Natural Gas** | | | | | | |
| Wisconsin | **1,493.8** | **40.5 %** | 1,196.2 | 41.2 % | 1,325.3 | 42.6 % |
| Illinois | **1,672.8** | **45.3 %** | 1,321.9 | 45.5 % | 1,357.1 | 43.6 % |
| Minnesota | **367.1** | **10.0 %** | 255.9 | 8.8 % | 281.5 | 9.0 % |
| Michigan | **156.5** | **4.2 %** | 131.5 | 4.5 % | 148.7 | 4.8 % |
| Total natural gas | **3,690.2** | **100.0 %** | 2,905.5 | 100.0 % | 3,112.6 | 100.0 % |
| **Total utility operating revenues** | **$ 8,228.8** | | $ 7,179.5 | | $ 7,430.2 | |

**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 2021, along with the approved ROE and capital structure for each utility during 2021.

| Regulated Retail Rates | Regulatory Commission | Authorized ROE | Average Common Equity Component |
|---|---|---|---|
| WE – electric, natural gas, and steam | PSCW | 10.0% | 52.5% |
| WPS – electric and natural gas | PSCW | 10.0% | 52.5% |
| WG – natural gas | PSCW | 10.2% | 52.5% |
| UMERC – electric (former WE customers) | MPSC | 10.1% | 55.3% |
| UMERC – electric (former WPS customers) | MPSC | 10.2% | 52.94% |
| PGL – natural gas | ICC | 9.05% | 50.33% |
| NSG – natural gas (prior to September 15, 2021) | ICC | 9.05% | 50.48% |
| NSG – natural gas (effective September 15, 2021) | ICC | 9.67% | 51.58% |
| MERC – natural gas | MPUC | 9.7% | 50.9% |
| MGU – natural gas [1] | MPSC | 9.9% | 52.0% |

[1] In accordance with MGU's most recent rate order, effective January 1, 2022, MGU's retail natural gas rates reflect a 9.85% authorized ROE and an average common equity component of 51.5%. 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 2021 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 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 bid-based energy markets. MISO is responsible for monitoring and ensuring equal access to the electric transmission system in its footprint.

In MISO, base transmission costs are currently being paid by load-serving entities located in the service territories of each MISO transmission owner. The FERC has previously confirmed the use of the current transmission cost allocation methodology. Certain additional costs for new transmission projects are allocated throughout the MISO footprint.

As part of MISO, a market-based platform is used for valuing transmission congestion premised upon an LMP system. 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 were completed for the period of June 1, 2021, through May 31, 2022. The resulting ARR allocation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

MISO has an annual zonal resource adequacy requirement to ensure there is sufficient generation capacity to serve the MISO market. To meet this requirement, capacity resources can be acquired through MISO's annual capacity auction, bilateral contracts for capacity, or provided from generating or demand response resources. All of our capacity requirements during the planning year from June 1, 2021, through May 31, 2022 were met.

### *Other Electric Regulations*

Our electric utilities are subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act amended the Federal Power Act in 2005 to, among other things, make electric utility industry consolidation more feasible, authorize the FERC to review proposed mergers and the acquisition of generation facilities, change the FERC regulatory scheme applicable to qualifying cogeneration facilities, and modify certain other aspects of energy regulations and federal tax policies applicable to us. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by the FERC, which established 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.

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

### *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 Pipeline and Hazardous Materials Safety Administration 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 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 Pipeline and Hazardous Materials Safety Administration 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 United States Department of Energy and the Canadian National Energy Board are also required, along with routine reporting related to imports and exports.

Bishop Hill III, Blooming Grove, Coyote Ridge, Jayhawk, Tatanka Ridge, and Upstream are all 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 foster a diverse workforce and inclusive workplace; attract, retain and develop talented personnel; and keep our employees safe and healthy.

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, diversity and inclusion, 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, including succession planning. The Compensation Committee reviews recruiting and development programs and priorities, receives updates on key talent, and assesses workforce diversity across the organization.

### Workforce

As of December 31, 2021, we had the following number of employees, including those represented under union agreements:

| | Total Employees | Union Employees |
|---|---|---|
| WE | 2,409 | 1,869 |
| WPS | 1,139 | 803 |
| WG | 355 | 235 |
| PGL | 1,310 | 878 |
| NSG | 157 | 111 |
| MERC | 206 | 42 |
| MGU | 136 | 89 |
| WBS | 1,226 | — |
| **Total employees** | 6,938 | 4,027 |

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.

### Diversity and Inclusion

We are committed to fostering a diverse workforce and inclusive workplace. Our commitment is a core strategic competency and an integral part of our culture. As of December 31, 2021, women and minorities each represented approximately 25% of our workforce. We have a number of initiatives that promote diverse workforce contributions, educate employees about diversity and inclusion, and ensure our companies are attractive employers for persons of diverse backgrounds. These initiatives include nine business resource groups (voluntary, employee-led groups organized around a particular shared background or interest), mentoring programs, and training for leaders on countering unconscious bias, building inclusive teams, and preventing workplace harassment. We also support external leadership and educational programs that support, train, and promote women and minorities 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 Occupational Safety and Health Administration (OSHA) lost-time incidents and days away, restricted or transferred (DART) metrics, as well as 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.

In response to the COVID-19 pandemic, we have implemented safety protocols and new procedures to protect our employees and customers. See Factors Affecting Results, Liquidity, and Capital Resources – Coronavirus Disease – 2019, for additional information.

## 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 regulation and oversight.***

We are subject to significant state, local, and federal governmental regulations, including regulations by the various utility commissions in the states where we serve customers. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, and cause us to incur substantial compliance and other costs. Changes in regulations, interpretations of regulations, or the imposition of new regulations could also significantly impact us, including requiring us to change our business operations. Many aspects of our operations are regulated and impacted by government regulation, 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 and accounting; 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, and 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 of regulatory assets 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.

The QIP rider provides PGL with recovery of, and a return on, qualifying natural gas infrastructure investments that are placed in service between regulatory rate reviews. Infrastructure investments under the QIP rider earn a return at the applicable weighted average cost of capital. Without legislative action, the QIP rider will sunset after December 2023. If the QIP rider is not extended or there is no other regulatory change, PGL will be subject to regulatory lag on its natural gas infrastructure investments that are placed in service between regulatory rate reviews, which could have a material adverse impact on PGL's, and correspondingly our, results of operations, financial position, 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, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits 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 costs of complying with regulations or other associated costs in customer rates in a timely manner, or if we are unable to obtain, renew, or comply with these 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, $SO_2$, and NOx), protection of natural resources, water quality, wastewater discharges, and management of hazardous and toxic substances and solid wastes and soils. For example, the EPA adopted and implemented (or is in the process of implementing) regulations governing the emission of NOx, ozone, fine particulates, and other air pollutants under the CAA through the NAAQS, climate change regulations, New Source Performance Standards for GHG emissions from new, modified, and reconstructed fossil-fueled power plants, and other air quality regulations. The EPA also finalized regulations under the Clean Water Act that govern cooling water intake structures at our power plants and revised the effluent guidelines for steam electric generating plants. Several of these rules are being challenged or reviewed by agencies under the Biden Administration's Executive Order 13990, which creates additional uncertainty. As a result of these challenges and reviews, existing environmental laws and regulations may be revised or new laws or regulations may be adopted at the federal, state, or local level.

We incur significant capital and operating resources to comply with these 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 potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations.

As a result of these compliance costs and other factors, certain of our coal-fired electric generating facilities have become uneconomical to maintain and operate, which has resulted in these units being retired or converted to an alternative type of fuel. As part of our commitment to a cleaner energy future, we have already retired more than 1,800 MW of coal-fired generation since the beginning of 2018. Under the ESG Progress Plan, we expect to retire approximately 1,600 MW of additional fossil-fueled generation by 2025, to be replaced with the construction of zero-carbon-emitting renewables and clean natural gas-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 emission reduction goals.***

There is continued scientific and political attention to issues concerning the existence and extent of climate change. Management expects this attention to continue since climate change is one of President Biden's primary initiatives, with significant actions expected by his administration during his term in office. As a result, we expect the EPA and states to adopt and implement additional regulations to restrict emissions of GHGs. In addition, there is increasing activism from other stakeholders, including institutional investors and other sources of financing, to accelerate the transition to lower GHG emissions.

Costs associated with such legislation, regulation, and emission reduction goals could be significant. GHG regulations that may be adopted in the future, at either the federal or state level, or other necessary changes to our ESG Progress Plan, may cause our environmental compliance spending to differ materially from the amounts currently estimated. These regulations, as well as changes in the fuel markets and advances in technology, could make additional electric generating units uneconomic to maintain or operate, may impact how we operate our existing fossil-fueled power plants and biomass facility, and could affect unit retirement and replacement decisions in the future under the ESG Progress Plan. These regulations could also adversely affect our future results of operations, cash flows, and financial condition. There is no guarantee that we will be allowed to fully recover costs incurred to comply with these and other federal and state regulations or that cost recovery will not be delayed or otherwise conditioned.

In addition, our natural gas delivery systems and natural gas storage fields may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair. Fugitive gas typically vents to the atmosphere and consists primarily of methane. $CO_2$ is also a byproduct of natural gas consumption. Certain states outside our service territories have passed legislation banning natural gas used in new construction in order to limit these GHG emissions. Future statewide or nationwide actions like these to regulate GHG emissions could increase the price of natural gas, restrict the use of 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. A significant increase in the price of natural gas may increase rates for our natural gas customers, which could reduce natural gas demand.

In May 2021, we announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by 2025 and by 80% by 2030, both from a 2005 baseline. Over the longer term, the target for our generation fleet is net-zero $CO_2$ emissions by 2050. We also believe we will be in a position to eliminate coal as an energy source by 2035. 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. Our plan to replace older, fossil-fueled generation with zero-carbon emitting renewables and clean natural gas-fueled generation will contribute to the achievement of our goals related to reducing $CO_2$ and methane emissions as well as coal as an energy source. However, our ability to achieve such goals depends on many external factors, including the development of relevant energy technologies and the ability to execute our capital plan. These efforts could impact how we operate our electric generating units and natural gas facilities and lead to increased competition and regulation, all of which could have a material adverse effect on our operations and financial condition.

***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 or our subsidiaries' credit ratings.***

Tax legislation and regulations can adversely affect, among other things, our financial condition, results of operations, cash flows, liquidity, and credit ratings. Future changes to corporate tax rates or policies, including under the Biden Administration, could require us to take material charges against earnings. Such changes include, among other things, increasing the federal corporate income tax rate, disallowing use of certain 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, 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 use to reduce our federal tax obligations. The amount of tax credits we earn depends on the amount of electricity produced, the applicable tax credit rate, or the amount of the investment in qualifying property. 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 wind parks we have invested in, resulting in a material adverse impact on our financial condition and results of operations. In addition, any reductions or eliminations of these tax credits or other governmental incentives that promote renewable energy generating facilities may limit our ability to make further investments in renewable energy generating facilities or reduce the returns on our existing investments.

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 or any of our subsidiaries 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 cyber security assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. If our electric utilities are found to be in noncompliance with the mandatory reliability standards, they could be subject to 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**

***The ongoing COVID-19 pandemic has adversely affected, and could continue to adversely affect, our business functions, financial condition, liquidity, and results of operations.***

The COVID-19 pandemic has adversely impacted the economy and financial markets, which has adversely affected our businesses. During 2021, commercial and industrial retail sales volumes began to improve due to the continued economic recovery in our service territories. However, there are still questions regarding the extent and duration of the COVID-19 pandemic itself. Orders limiting the capacity of various businesses could be adopted in the future depending on how the virus continues to mutate and spread. The resulting effects of any future orders could have a variety of adverse impacts on us and our subsidiaries, 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.

The COVID-19 pandemic and any additional related government responses could impair our and our subsidiaries' 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 reduced labor availability and productivity as a result of COVID-19 infections, although we have taken precautions with regard to employee hygiene and facility cleanliness, imposed travel limitations on our employees, implemented additional protocols for our field employees who travel to customer premises, provided additional employee benefits, and implemented remote work policies where appropriate. We could also be impacted by possible labor disruptions, employee attrition, and a reduced ability to replace departing employees as a result of employees who leave or forego employment to avoid surcharges imposed on our medical plan or other required precautionary measures.

Despite our efforts to manage the impacts of the COVID-19 pandemic, the extent to which COVID-19 may continue to affect us depends on factors beyond our knowledge or control. Therefore, we are currently unable to determine what additional impact the COVID-19 pandemic may have on our business plans and operations, liquidity, financial condition, and results of operations, but will continue to monitor COVID-19 developments and modify our plans as conditions change.

***Our operations are subject to risks arising from the reliability 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, natural gas and electric distribution facilities, natural gas storage fields, and renewable energy facilities. The operation of these facilities involves many risks, including operator error and the breakdown or failure of equipment or processes.

Potential breakdown or failure may occur due to severe weather as a result of climate change or otherwise (i.e., storms, tornadoes, floods, droughts, etc.); catastrophic events (i.e., fires, earthquakes, explosions, pandemic health events, etc.); significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; 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 attacks; or cyber security intrusions. Any of these events could lead to substantial financial losses, including increased maintenance costs, unanticipated capital expenditures, and a reduction of revenues related to our non-utility renewable energy facilities. 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. Unplanned outages at our power plants may reduce our revenues, 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.

Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of these lost revenues or increased expenses, which could adversely affect our results of operations and cash flows.

***Our operations are subject to various conditions that can result in fluctuations in energy sales to customers, including 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. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate substantially on a seasonal basis. In addition, milder temperatures during the summer cooling season and during the winter heating season, as a result of climate change or otherwise, may result in lower revenues and net income.
- *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. 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 reduced sales from effective conservation measures or the adoption of new technologies, could adversely impact our results of operations and financial condition.

***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. An extreme weather event could result in downed wires and poles or damage to other operating equipment, which could result in us foregoing sales of electricity and lost revenues. Due to the cold temperatures, wind, snow, and ice throughout the central part of the country during February 2021, the cost of gas purchased for our natural gas utility customers and for the use of fuel at our generation facilities was temporarily driven significantly higher than our normal winter weather expectations. Although our utilities have regulatory mechanisms in place for recovering all prudently incurred gas costs, regulatory commissions could disallow recovery or order the refund of any costs determined to be imprudent.

In addition, 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 wind storms, floods, tornadoes, snow and ice storms, or abnormal levels of precipitation. Extreme weather may 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.

Our corporate strategy may be impacted by policy and legal, technology, market, and reputational risks and opportunities that are associated with the transition to lower GHG emissions. In addition, changes in policy to combat climate change, including mitigation and adaptation efforts, and technology advancement, each of which can also accelerate the implications of a transition to lower emissions, may materially adversely impact our results of operations and cash flows through significant capital expenditures and investments in renewable generation.

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

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. Current domestic and global supply chain disruptions are delaying the delivery, and in some cases resulting 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 infrastructure growth, including our renewable energy projects.

Moreover, prices of equipment, materials, and other resources have increased recently as a result of these supply chain disruptions and may continue to increase in the future, as a result of inflation. Although inflation in the United States has been relatively low in recent years, during 2021 the United States economy began experiencing a significant inflationary effect. While we cannot predict any future trends in the rate of inflation, the global COVID-19 pandemic and other factors have brought uncertainty to the near-term economic outlook. Increases in inflation raise our costs for labor, materials, and services, 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 financial condition and results of operations.

***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 storage, and other projects, including projects for environmental compliance. We also expect to continue constructing and investing in renewable energy generating facilities as part of the ESG Progress Plan, including repowering existing wind generation projects in our generation portfolio, and as part of our non-utility energy infrastructure segment. In addition, WBS continues to invest in technology and the development of software applications to support our utilities.

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. For example, the timing of the completion of Badger Hollow I was impacted by supply chain disruptions, primarily related to the COVID-19 pandemic. Additional supply chain disruptions, including solar panel shortages and increasing material costs as a result of government tariffs and other factors, could impact the timing of completion of our other 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; the impact of pandemic health events; other governmental actions; continued public and policymaker support for such projects; and events in the global economy. In addition, 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 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.

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 our (or their) capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

***Our operations are subject to risks beyond our control, including but not limited to, cyber security intrusions, terrorist 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. Despite the implementation of security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to physical or cyber security intrusions caused by human error, vendor bugs, terrorist attacks, or other malicious acts. These 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.

We operate in an industry that requires the use of sophisticated information technology systems and network infrastructure, which control an interconnected system of generation, distribution, and transmission systems shared with third parties. A successful physical or cyber security intrusion may occur despite our security measures or those that we require our vendors to take, which include compliance with reliability standards and critical infrastructure protection standards. Successful cyber security 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. We implement procedures to protect our systems, but we cannot guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. The failure of any of these or other similarly 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. Security breaches 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.

***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. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, solar cells, and related energy storage devices, which have become more cost competitive than they were in the past. It is possible that 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.

We 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 transport, distribute, and store natural gas, which involves numerous risks that may result in accidents and other operating risks and costs.***

Inherent in natural gas distribution and storage activities are a variety of hazards and operational risks, such as leaks, accidental explosions, and mechanical problems, which could materially and adversely affect our results of operations, financial condition, and cash flows. In addition, these risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, impairment of operations, and substantial losses to us. The location of natural gas pipelines and storage facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may 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.

***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 wind energy depends heavily on suitable wind conditions, which are variable. If wind conditions are unfavorable or below our estimates as a result of climate change or otherwise, our electricity production, and therefore our revenues and PTCs earned from our non-utility renewable energy facilities, may be substantially below our expectations. We base our decisions about which sites to acquire and operate in part on the findings of long-term wind and other meteorological data and studies conducted in the proposed area, which measure the wind's speed and prevailing direction and seasonal variations. Actual conditions at these sites, however, may not conform to the measured data in these studies. For example, if there is an increase in frequency and severity of weather conditions, the disruptions to our sites may become more frequent and severe.

For the majority of our non-utility renewable energy operations, we have entered into long-term PPAs with a small number of customers to purchase the energy produced 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 operation of the facility on a profitable basis. Decreases in the retail prices of electricity supplied by traditional utilities or other clean energy sources in the areas where our non-utility renewable energy facilities are located could harm our ability to offer competitive pricing and could harm our ability 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 customers is impacted by wholesale prices at a market hub location different than the location of our wind farms. Systemic shortfalls and disruptions in transmission capacity can cause congestion between the two locations, which along with other factors, can increase price disparity. This price difference, 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 ability to acquire new non-utility renewable energy facilities or generate revenue from existing facilities depends on having interconnection arrangements with transmission providers and a reliable electricity grid. We cannot predict whether transmission facilities will be expanded in specific markets to accommodate or increase competitive access to those markets. In addition, 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. This risk of 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.

***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. In addition, current and prospective employees may determine that they do not wish to work for us. For example, we are currently subject to workforce trends occurring in the United States triggered by the decisions of employees to leave the workforce and/or their employer at higher rates as compared with prior years. This high demand for replacement employees as a result of this trend may lead to higher labor costs than currently budgeted for and adversely affect our results of operations. 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 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. 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. Interest rates may increase in the future, which may affect our results of operations and the ability of our regulated subsidiaries to earn their approved rates of return. Rising interest rates may also impair our ability to cost-effectively finance capital expenditures and to refinance maturing debt.

Our or our subsidiaries' access to the credit and capital markets could be limited, or our or our subsidiaries' 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;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- Changes in investment criteria of institutional investors or banks, including any policies that would limit or restrict funding for companies with fossil fuel-related investments;
- War or the threat of war;
- The overall health and view of the utility and financial institution industries; and
- The replacement of LIBOR with an alternative reference rate.

A portion of our indebtedness provides for interest at variable interest rates, primarily based on LIBOR. LIBOR is the subject of national, international, and other regulatory reform, which is expected to cause LIBOR to cease to exist after June 2023. Various alternative reference rates are being evaluated by market participants, with the secured overnight financing rate being the most widely adopted alternative to date. We cannot predict the consequences and timing of the development of alternative reference rates, or the performance of LIBOR as it is being phased out through June 2023. The transition to alternative reference rates could include an increase in our interest expense.

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 our current common stock dividend level.

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

There are a number of factors that impact our and our subsidiaries' credit ratings, including, but not limited to, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We or any of our subsidiaries could experience a downgrade in ratings if the rating agencies determine that the level of business or financial risk of us, 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;
- Require the payment of higher interest rates in future financings and possibly reduce the pool of creditors;
- Decrease funding sources by limiting our or our subsidiaries' access to the commercial paper market;
- Limit the availability of adequate credit support for our subsidiaries' operations; and
- Trigger collateral requirements in various contracts.

***Fluctuating commodity prices could negatively impact our electric and natural gas utility 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 has increased, and may continue to 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.

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 commodity 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, 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; 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, the COVID-19 pandemic, and supplier financial hardship. Supplier financial hardship is a result of decreased demand for coal due to increased natural gas and renewable energy generation, the impact of environmental regulations, and environmental concerns related to coal-fired generation.

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. In addition, legislation or regulation that supports distributed energy technologies or that allows third party sales from such technologies could result in further competition. This increased competition in the retail and wholesale 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. All market participants, including us, must submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes an LMP that reflects the market price for energy. We are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining the stability of the transmission system. 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, allowing for more efficient use of generation assets in the MISO Energy Markets. These market designs continue to have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the MISO Energy Markets, and the costs associated with 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.

***We may experience poor investment performance of benefit plan holdings due to changes in assumptions and market conditions.***

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, 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 that could become impaired.***

We assess goodwill for impairment on an annual basis or whenever events or circumstances occur that indicate a potential for impairment. If goodwill is deemed to be impaired, we may be required to incur non-cash charges that could materially adversely affect our results of operations. At December 31, 2021, our goodwill was $3,052.8 million.

***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 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, 2021:

| Name | Location | Fuel | Number of Generating Units | Capacity In MW [1] |
|---|---|---|---|---|
| **Coal-fired plants** | | | | |
| Columbia | Portage, WI | Coal | 2 | 311 [2] |
| ERGS | Oak Creek, WI | Coal | 2 | 1,061 [3] [4] |
| OCPP | Oak Creek, WI | Coal | 4 | 1,087 |
| Weston | Rothschild, WI | Coal | 2 | 720 [2] |
| **Total coal-fired plants** | | | 10 | 3,179 |
| **Natural gas-fired plants** | | | | |
| Concord | Watertown, WI | Natural Gas/Oil | 4 | 366 |
| De Pere Energy Center | De Pere, WI | Natural Gas/Oil | 1 | 165 |
| Fox Energy Center | Wrightstown, WI | Natural Gas | 3 | 577 |
| Germantown | Germantown, WI | Natural Gas/Oil | 5 | 273 |
| F. D. Kuester | Negaunee, MI | Natural Gas | 7 | 132 |
| A. J. Mihm | Baraga, MI | Natural Gas | 3 | 56 |
| Paris | Union Grove, WI | Natural Gas/Oil | 4 | 359 |
| PWGS | Port Washington, WI | Natural Gas | 2 | 1,228 [4] |
| Pulliam | Green Bay, WI | Natural Gas/Oil | 1 | 81 |
| VAPP | Milwaukee, WI | Natural Gas | 2 | 267 |
| West Marinette | Marinette, WI | Natural Gas/Oil | 3 | 150 |
| Weston | Rothschild, WI | Natural Gas/Oil | 3 | 65 |
| **Total natural gas-fired plants** | | | 38 | 3,719 |
| **Renewables** | | | | |
| Hydro plants (30 in number) | WI and MI | Hydro | 81 | 116 [5] [6] |
| Rothschild Biomass Plant | Rothschild, WI | Biomass | 1 | 44 [7] |
| Badger Hollow I | WI | Solar | 41 | 100 [2] |
| Two Creeks | WI | Solar | 48 | 100 [2] |
| Wind sites (5 in number) | WI and IA | Wind | 350 | 493 [2] |
| **Total renewables** | | | 521 | 853 |
| **Total system** | | | 569 | 7,751 |

[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 2022 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] These facilities are jointly owned by WPS and various other utilities. The capacity indicated for each of these units is equal to WPS's portion of total plant capacity based on its percent of ownership.

- Wisconsin Power and Light Company, an unaffiliated utility, operates the Columbia units. WPS holds a 27.5% ownership interest in Columbia.

- WPS operates the Weston 4 facility and holds a 70.0% ownership interest in this facility. Dairyland Power Cooperative, an unaffiliated energy cooperative, holds the remaining 30.0% interest.

- Badger Hollow I is jointly owned by WPS and Madison Gas and Electric Company, an unaffiliated utility. WPS holds a 66.7% ownership interest in this facility and Madison Gas and Electric Company owns the remaining 33.3%.

- Two Creeks is jointly owned by WPS and Madison Gas and Electric Company, an unaffiliated utility. WPS holds a 66.7% ownership interest in this facility and Madison Gas and Electric Company owns the remaining 33.3%.

- Forward Wind is jointly owned by WPS along with Wisconsin Power and Light Company and Madison Gas and Electric Company, two unaffiliated utilities. WPS holds a 44.6% ownership interest in this facility and the unaffiliated utilities collectively own the remaining 55.4%.

(3) This facility is jointly owned by We Power and two other unaffiliated entities. Our share of capacity is equal to We Power's ownership interest of 83.34%.

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

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

(6) 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 MW and 10.3 MW, respectively.

(7) 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.

As of December 31, 2021, we operated approximately 35,800 miles of overhead distribution lines and approximately 35,600 miles of underground distribution cable, as well as approximately 440 electric distribution substations and approximately 510,500 line transformers.

## Natural Gas Facilities

At December 31, 2021, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 50,900 miles of natural gas distribution mains,
- Approximately 1,200 miles of natural gas transmission mains,
- Approximately 2.3 million natural gas lateral services,
- Approximately 500 natural gas distribution and transmission gate stations,
- Approximately 68.2 Bcf of working gas capacities in underground natural gas storage fields:
    - Bluewater, 26.5 Bcf of fields located in southeastern Michigan,
    - Manlove, a 38.8 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,
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquefied petroleum gas located in Illinois,
- Peak propane air systems providing approximately 2,960 Dth per day, and
- LNG storage plants with a total send-out capability of 73,600 Dth per day.

Our natural gas distribution and gas storage systems included distribution mains and transmission mains connected to the pipeline transmission systems of Alliance Pipeline, ANR Pipeline Company, Centra Pipelines, Bison Pipeline, Consumers Energy, DTE Gas Company, 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, Union Gas, 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, 2021, 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 generating facilities to WE. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases. Bluewater provides natural gas storage and hub services primarily to WE, WPS, and WG, and also provides these same services to several unaffiliated companies. WECI has ownership interests in six wind generating facilities. For more information on recent and pending wind facility acquisitions, see Note 2, Acquisitions.

The following table summarizes information on WECI's wind generating facilities as of December 31, 2021:

| Name | Location | Number of Generating Units | Nameplate Capacity In MW [1] |
|---|---|---|---|
| **Wind generating facilities** | | | |
| Bishop Hill III | Henry County, Illinois | 53 | 132.1 |
| Upstream | Antelope County, Nebraska | 81 | 202.5 |
| Coyote Ridge | Brookings County, South Dakota | 39 | 96.7 |
| Blooming Grove | McLean County, Illinois | 94 | 250.0 |
| Tatanka Ridge | Deuel County, South Dakota | 56 | 155.0 |
| Jayhawk | Bourbon and Crawford Counties, Kansas | 70 | 197.4 |
| **Total wind generating facilities** | | 393 | 1,033.7 |

(1) Nameplate capacity is the amount of energy a turbine should produce at optimal wind speeds.

## ITEM 3. LEGAL PROCEEDINGS

The following should be read in conjunction with Note 24, Commitments and Contingencies, and Note 26, Regulatory Environment, in this report for additional information on material legal proceedings and matters related to us and our subsidiaries.

In addition to those legal proceedings discussed in Note 24, Commitments and Contingencies, Note 26, Regulatory Environment, and below, 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.

### Environmental Matters

### *Manlove Field Matter*

In September 2017, the IDNR, Office of Oil and Gas Resource Management, issued a VN to PGL related to a leak of natural gas from a well located at the PGL Manlove Gas Storage Field in December 2016. PGL quickly shut down and permanently plugged the well to contain the leak after it was discovered. The leak resulted in the migration of natural gas from the well to the Mahomet Aquifer located in central Illinois and impacted residential freshwater wells. PGL has been working with residents potentially impacted by the natural gas leak, and the Illinois state agencies to investigate and remediate the impacts of the natural gas leak to the Mahomet Aquifer. In October 2017, the Illinois AG filed a complaint against PGL alleging certain violations of the Illinois Environmental Protection Act and the Oil and Gas Act. PGL entered into an Agreed Interim Order with the State of Illinois in October 2017 and a First Amended Agreed Interim Order in September 2019 whereby PGL agreed, among other things, to continue actions it was already undertaking proactively, including the submittal of a GMZ application to the IEPA. A supplemental filing was sent to the IEPA in December 2019. In September 2020, the IEPA sent PGL a letter conditionally approving the GMZ application. During late 2020 and throughout 2021, PGL has taken steps to implement the requirements of the approved GMZ project.

In addition, in December 2017, the IEPA issued a VN to PGL alleging the same violations as the AG. Lastly, in January 2018, the IEPA issued a VN alleging certain violations of Illinois air emission rules arising from the construction and operation of flaring equipment at the leak site. Both of the IEPA VN matters have been referred to the AG for enforcement.

In the complaint, as is customary in these types of actions, the AG cited to the statutory penalties allowed by law. Ultimately, the pursuit of any civil penalties is at the AG’s discretion. In the event the AG pursues penalties in connection with a final order, we believe that PGL's high level of cooperation and quick action to remedy the situation and to work with the potentially impacted homeowners would be taken into account. At this time, we believe that civil penalties, if any, 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 they resign, die, or are removed 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 49
- WEC Business Services (a centralized service company of WEC Energy Group) – Vice President and Deputy General Counsel since August 2021. Director-Legal Services – Corporate and Finance from June 2015 through July 2021.

**Robert M. Garvin.** Age 55.
- WEC Energy Group — Executive Vice President - External Affairs since June 2015.
- WEC Business Services (a centralized service company of WEC Energy Group) – Executive Vice President - External Affairs since January 2019.
- WE — Executive Vice President - External Affairs from June 2015 through December 2018.

**William J. Guc.** Age 52.
- WEC Energy Group — Controller since October 2015. Vice President since June 2015.
- WE — Vice President and Controller since October 2015. Assistant Corporate Secretary since January 2020.

**Margaret C. Kelsey.** Age 57.
- WEC Energy Group — Executive Vice President, Corporate Secretary and General Counsel since January 2018. Executive Vice President from September 2017 to January 2018.
- WE — Executive Vice President, Corporate Secretary and General Counsel since January 2018. Director since January 2018.
- Modine Manufacturing Company – General Counsel, Corporate Secretary, and Vice President - Legal from April 2008 to August 2017. Vice President - Corporate Communications from April 2014 to August 2017. Modine Manufacturing Company is a manufacturer of thermal management systems and components.

**Gale E. Klappa.** Age 71.
- WEC Energy Group — Executive Chairman since February 2019. Chairman of the Board and Chief Executive Officer from October 2017 to February 2019, and from May 2004 to May 2016. Non-Executive Chairman of the Board from May 2016 to October 2017. President from April 2003 to August 2013. Director since December 2003.
- WE — Director since January 2018, and from December 2003 to May 2016. Chairman of the Board from January 2018 to February 2019, and from May 2004 to May 2016. Chief Executive Officer from January 2018 to February 2019, and from August 2003 to May 2016. President from April 2003 to June 2015.

**Daniel P. Krueger.** Age 56.
- WEC Business Services (a centralized service company of WEC Energy Group) — Executive Vice President - WEC Infrastructure since January 2019. Executive Vice President from November 2018 to January 2019.
- WE — Senior Vice President - Wholesale Energy and Fuels from June 2015 to November 2018.

**Scott J. Lauber.** Age 56.
- WEC Energy Group — President and Chief Executive Officer since February 1, 2022. Senior Executive Vice President and Chief Operating Officer from June 2020 to January 31, 2022. Senior Executive Vice President and Chief Financial Officer from October 2019 to June 2020. Senior Executive Vice President, Chief Financial Officer and Treasurer from February 2019 to October 2019. Executive Vice President, Chief Financial Officer and Treasurer from October 2018 to February 2019. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from February 2013 to March 2016. Director since February 1, 2022.
- WE — Chairman of the Board and Chief Executive Officer since February 1, 2022. President since January 1, 2022. Executive Vice President from June 2020 to December 31, 2021. Executive Vice President and Chief Financial Officer from October 2019 to June 2020, and from April 2016 to October 2018. Executive Vice President, Chief Financial Officer and Treasurer from October 2018 to October 2019. Vice President and Treasurer from February 2013 to March 2016. Director since April 2016.

**Xia Liu.** Age 52.
- 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.
- CenterPoint Energy, Inc. — Senior Advisor from April 2020 to May 2020. Executive Vice President and Chief Financial Officer from April 2019 to April 2020. CenterPoint Energy, Inc. is a public utility holding company whose operating subsidiaries provide electric and natural gas service to customers in parts of the South and Midwest.

- Georgia Power Company — Executive Vice President, Chief Financial Officer and Treasurer from October 2017 to April 2019. Georgia Power Company is a utility subsidiary of The Southern Company that provides electric service to customers throughout Georgia.
- Gulf Power Company — Vice President, Chief Financial Officer and Treasurer from July 2015 to October 2017. Gulf Power Company, previously a utility subsidiary of The Southern Company, serves customers in northwest Florida.

**William Mastoris.** Age 58.
- WEC Business Services (a centralized service company of WEC Energy Group) – Executive Vice President – Customer Service and Operations since December 2021. Vice President – Supply Chain and Fleet from January 2019 through November 2021. Director since November 2021.
- WE – Executive Vice President – Customer Service and Operations since December 2021. Vice President – Supply Chain and Fleet from June 2015 through December 2018. Director since November 2021.

**Charles R. Matthews.** Age 65.
- PELLC — President since June 2015.
- PGL — Director, President, and Chief Executive Officer since June 2015.
- NSG — Director, President, and Chief Executive Officer since June 2015.

**Molly A. Mulroy.** Age 46.
- WEC Business Services (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.
- WE – Vice President and Chief Information Officer from June 2015 through December 2018.

**Anthony L. Reese.** Age 40.
- WEC Energy Group — Vice President and Treasurer since October 2019.
- WE — Vice President and Treasurer since October 2019.
- PGL – Controller - Illinois from September 2015 to September 2019.

**Mary Beth Straka.** Age 57.
- 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 December 31, 2021, based upon the number of WEC Energy Group shareholder accounts (including accounts in our stock purchase and dividend reinvestment plan), we had approximately 39,000 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

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 American Transmission Company LLC (ATC) (a for-profit electric transmission company regulated by the Federal Energy Regulatory Commission and certain state regulatory commissions), and non-utility energy infrastructure operations through W.E. Power LLC (which owns generation assets in Wisconsin), Bluewater Natural Gas Holding LLC (which owns underground natural gas storage facilities in Michigan), and WEC Infrastructure LLC (WECI), which holds ownership interests in several wind generating facilities.

### Corporate Strategy

Our goal is to continue to build and sustain long-term value for our shareholders and customers by focusing on the fundamentals of our business: environmental stewardship; reliability; operating efficiency; financial discipline; exceptional customer care; and safety. Our capital investment plan for efficiency, sustainability and growth, referred to as our ESG Progress Plan, provides a roadmap for us to achieve this goal. It is an aggressive plan to cut emissions, maintain superior reliability, deliver significant savings for customers, and grow 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. We published the results of a priority sustainability issue assessment in 2020, identifying the issues that are most important to our company and its stakeholders over the short and long terms. Our risk and priority assessments have formed our direction as a company.

#### *Creating a Sustainable Future*

Our ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fired generation. When taken together, the retirements and new investments should better balance our supply with our demand, while maintaining reliable, affordable energy for our customers. The retirements will contribute to meeting our goals to reduce carbon dioxide ($CO_2$) emissions from our electric generation.

In May 2021, we announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by 2025 and by 80% by 2030, both from a 2005 baseline. We expect to achieve these goals by making operating refinements, retiring less efficient generating units, and executing our capital plan. Over the longer term, the target for our generation fleet is net-zero $CO_2$ emissions by 2050.

As part of our path toward these goals, we are exploring co-firing with natural gas at our ERGS coal-fired units. By the end of 2030, we expect our use of coal will account for less than 5% of the power we supply to our customers, and we believe we will be in a position to eliminate coal as an energy source by 2035.

We already have retired more than 1,800 megawatts (MW) of coal-fired generation since the beginning of 2018, which included the 2019 retirement of the Presque Isle power plant as well as the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating units. See Note 6, Regulatory Assets and Liabilities, for more information related to these power plant retirements. Through our ESG Progress Plan, we expect to retire approximately 1,600 MW of additional fossil-fueled generation by 2025, which includes the planned retirements in 2023-2024 of Oak Creek Power Plant Units 5-8 and the jointly-owned Columbia Units 1-2.

In addition to retiring these older, fossil-fueled plants, we expect to invest approximately $3.5 billion from 2022-2026 in regulated renewable energy in Wisconsin. Our plan is to replace a portion of the retired capacity by building and owning zero-carbon-emitting renewable generation facilities that are anticipated to include the following new investments:

- 1,400 MW of utility-scale solar;
- 800 MW of battery storage; and
- 100 MW of wind.

We also plan on investing in a combination of clean, natural gas-fired generation, including:

- 100 MW of reciprocating internal combustion engine (RICE) natural gas-fueled generation;
- the planned purchase of up to 200 MW of capacity in the West Riverside Energy Center – a new, combined-cycle natural gas plant completed by Alliant Energy in Wisconsin; and
- the planned purchase of the Whitewater Cogeneration Facility, a natural gas-fired combined cycle electric generating facility with a capacity of 236.5 MW.

The new investments discussed above are in addition to the renewable projects currently underway. For more details, see Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

In addition, we previously received approval from the Public Service Commission of Wisconsin (PSCW) to invest in 300 MW of utility-scale solar within our Wisconsin segment. Wisconsin Public Service Corporation (WPS) has partnered with an unaffiliated utility to construct two solar projects now in service in Wisconsin: Two Creeks Solar Park (Two Creeks) and Badger Hollow Solar Park I (Badger Hollow I). WPS owns 100 MW of Two Creeks and 100 MW of Badger Hollow I for a total of 200 MW. Wisconsin Electric Power Company (WE) has partnered with an unaffiliated utility to construct Badger Hollow Solar Park II, which is expected to enter commercial operation in the first quarter of 2023. Once constructed, WE will own 100 MW of this project.

In December 2018, WE received approval from the PSCW for two renewable energy pilot programs. The Solar Now pilot is expected to add a total of 35 MW of solar generation to WE's portfolio, allowing non-profit and governmental entities, as well as commercial and industrial customers, to site utility owned solar arrays on their property. Under this program, WE has energized 21 Solar Now projects and currently has another three under construction, together totaling more than 27 MW. The second program, the Dedicated Renewable Energy Resource pilot, would allow large commercial and industrial customers to access renewable resources that WE would operate, adding up to 150 MW of renewables to WE's portfolio, and helping these larger customers meet their sustainability and renewable energy goals.

In August 2021, the PSCW approved pilot programs for WE and WPS to install and maintain electric vehicle (EV) charging equipment for customers at their homes or businesses. The programs provide direct benefits to customers by removing cost barriers associated with installing EV equipment. In October 2021, subject to the receipt of any necessary regulatory approvals, we pledged to expand the EV charging network within the service territories of our electric utilities. In doing so, we joined a coalition of utility companies in a unified effort to make EV charging convenient and widely available throughout the Midwest. The coalition we joined is planning to help build and grow EV charging corridors, enabling the general public to safely and efficiently charge their vehicles.

We also continue to reduce methane emissions by improving our natural gas distribution system. We set a target across our natural gas distribution operations to achieve net-zero methane emissions by the end of 2030. We plan to achieve our net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of renewable natural gas (RNG) throughout our utility systems. We recently signed our first contract for RNG for our natural gas distribution business, which will be transporting the output of a local dairy farm onto our gas distribution system. The RNG supplied will directly replace higher-emission methane from natural gas that would have entered our pipes. This one contract represents 25 percent of our 2030 goal for methane reduction. We expect to have RNG flowing to our distribution network by the end of 2022.

As part of our effort to look for new opportunities in sustainable energy, we are testing the effects of blending hydrogen, a clean generating fuel, with natural gas for one of our RICE generating units in the Upper Peninsula of Michigan. We are partnering with the Electric Power Research Institute in this research that could help create another viable option for decarbonizing the economy. The project will be carried out in 2022, and the results will be shared across the industry.

### *Reliability*

We have made significant reliability-related investments in recent years, and in accordance with our ESG Progress 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 reliability projects that are proposed, currently underway, or recently completed.

- WE constructed approximately 46 miles of natural gas transmission main to increase the quantity and reliability of natural gas service in southeastern Wisconsin. This project, called the Lakeshore Lateral Project, was completed in October 2021.
- WE and Wisconsin Gas LLC (WG) have received approval to each construct their own liquefied natural gas (LNG) facility to meet anticipated peak demand. Commercial operation of the WE and WG LNG facilities is targeted for the end of 2023 and 2024, respectively.
- The Peoples Gas Light and Coke Company continues to work on its Safety Modernization Program, which primarily involves replacing 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.
- WPS completed its work in late 2021 on its System Modernization and Reliability Project, which involved modernizing parts of its electric distribution system, including burying or upgrading lines. WE, WPS, and WG also continue to upgrade their electric and natural gas distribution systems to enhance reliability.

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 the ESG Progress 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 disconnects and reconnects and enhances outage management capabilities.

We continue to focus on integrating the resources of all our businesses and finding the best and most efficient processes while meeting all applicable legal and regulatory requirements.

### *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 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 3, Dispositions, for information on the sale of certain WPS Power Development, LLC solar power generation facilities. See Note 2, Acquisitions, for information on our acquisition of Whitewater.

Our investment focus remains in our regulated utility and non-utility energy infrastructure businesses, as well as our investment in ATC. In our non-utility energy infrastructure segment, we have acquired or agreed to acquire majority interests in eight wind parks, with total available capacity of more than 1,550 MW. These renewable energy assets represent more than $2.3 billion in committed investments and have long-term agreements to serve customers outside our traditional service areas. Production tax credits from these wind investments reduce our cash tax expense. See Note 2, Acquisitions, for additional information on these transactions.

We expect total capital expenditures for our regulated utility and non-utility energy infrastructure businesses to be approximately $16.4 billion from 2022 to 2026. In addition, we currently forecast that our share of ATC's projected capital expenditures over the next five years will be $1.3 billion. Specific projects included in the $17.7 billion ESG Progress Plan are discussed in more detail below under Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

### *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.

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, 2021 with the year ended December 31, 2020. For a similar discussion that compares our results for the year ended December 31, 2020 with the year ended December 31, 2019, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations in Part II of our 2020 Annual Report on Form 10-K, which was filed with the SEC on February 25, 2021.

### Consolidated Earnings

The following table compares our consolidated results for the year ended December 31, 2021 with the year ended December 31, 2020, including favorable or better, "B", and unfavorable or worse, "W", variances:

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions, except per share data)*** | **2021** | **2020** | **B (W)** |
| Wisconsin | **$ 706.5** | $ 690.4 | $ 16.1 |
| Illinois | **223.0** | 203.5 | 19.5 |
| Other states | **35.8** | 39.0 | (3.2) |
| Electric transmission | **106.3** | 112.6 | (6.3) |
| Non-utility energy infrastructure | **279.2** | 260.8 | 18.4 |
| Corporate and other | **(50.5)** | (106.4) | 55.9 |
| **Net income attributed to common shareholders** | **$ 1,300.3** | $ 1,199.9 | $ 100.4 |
| | | | |
| **Diluted earnings per share** | **$ 4.11** | $ 3.79 | $ 0.32 |

Earnings increased $100.4 million during 2021, compared with 2020. The significant factors impacting the $100.4 million increase in earnings were:

- A $55.9 million decrease in the net loss attributed to common shareholders at the corporate and other segment, driven by lower interest expense, an increase in earnings from our equity method investments in technology and energy-focused investment funds, and the positive year-over-year impact from charges taken at Wispark during 2020. Higher net gains from investments held in the Integrys rabbi trust also contributed to the lower net loss. The investment gains from the rabbi trust offset higher benefit costs related to deferred compensation, which are included in other operation and maintenance expense in our operating segments. See Note 17, Fair Value Measurements, for more information on our investments held in the Integrys rabbi trust.

- A $19.5 million increase in net income attributed to common shareholders at the Illinois segment, driven by higher natural gas margins due to PGL's continued capital investment in the SMP project under its QIP rider and an increase in late payment charges. Lower benefit costs also contributed to the increase in earnings. These positive impacts were partially offset by higher depreciation expense and an increase in natural gas distribution and maintenance costs during 2021.

- An $18.4 million increase in net income attributed to common shareholders at the non-utility energy infrastructure segment, driven by an increase in PTCs generated in 2021, primarily due to our Blooming Grove and Tatanka Ridge wind parks that achieved commercial operation in December 2020 and January 2021, respectively. See Note 2, Acquisitions, and Note 16, Income Taxes, for more information. Partially offsetting this increase were operating losses at the Coyote Ridge and Tatanka Ridge wind parks related to congestion on the electricity grid due, in part, to several transmission outages in 2021. Higher interest expense due to WECI Wind Holding I's debt issuance in December 2020 also partially offset the positive impact from the increase in PTCs.

- A $16.1 million increase in net income attributed to common shareholders at the Wisconsin segment, driven by an increase in electric margins due to higher retail sales volumes, including the impact of weather. Also contributing to the increase were lower benefit costs and the positive impact of increased rates from the Wisconsin rate orders approved by the PSCW, which excludes all impacts related to the recognition of unprotected excess deferred tax benefits from the Tax Legislation as they had no impact on earnings. These positive impacts were partially offset by higher depreciation and amortization and the negative year-over-year impact from fuel and purchased power costs.

### *Non-GAAP Financial Measures*

The discussions below address the contribution of each of our segments to net income attributed to common shareholders. The discussions include financial information prepared in accordance with GAAP, as well as electric margins and natural gas margins, which are not measures of financial performance under GAAP. Electric margins (electric revenues less fuel and purchased power costs) and natural gas margins (natural gas revenues less cost of natural gas sold) are non-GAAP financial measures because they exclude other operation and maintenance expense, depreciation and amortization, and property and revenue taxes.

We believe that electric and natural gas margins provide 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 electric and natural gas margins internally when assessing the operating performance of our segments as these measures exclude the majority of revenue fluctuations caused by changes in these expenses. Similarly, the presentation of electric and natural gas margins herein is intended to provide supplemental information for investors regarding our operating performance.

Our electric margins and natural gas margins may not be comparable to similar measures presented by other companies. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance. The following table shows operating income by segment for our utility operations during years ended December 31, 2021 and 2020:

| | Year Ended December 31 | |
|---|---|---|
| *(in millions)* | **2021** | **2020** |
| Wisconsin | **$ 1,309.3** | $ 1,332.8 |
| Illinois | **361.6** | 330.8 |
| Other states | **52.4** | 61.6 |

Each applicable segment discussion below includes a table that provides the calculation of electric margins and natural gas margins, as applicable, along with a reconciliation to the most directly comparable GAAP measure, operating income.

## 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, 2021 was $706.5 million, representing a $16.1 million, or 2.3%, increase over the prior year. The higher earnings were driven by an increase in electric margins due to higher retail sales volumes, including the impact of weather. Also contributing to the increase were lower benefit costs and the positive impact of increased rates from the Wisconsin rate orders approved by the PSCW, which excludes all impacts related to the recognition of unprotected excess deferred tax benefits from the Tax Legislation as they had no impact on earnings. These positive impacts were partially offset by higher depreciation and amortization and the negative year-over-year impact from fuel and purchased power costs.

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions)*** | **2021** | **2020** | **B (W)** |
| Electric revenues | **$ 4,538.6** | $ 4,274.0 | $ 264.6 |
| Fuel and purchased power | **1,488.2** | 1,238.1 | (250.1) |
| Total electric margins | **3,050.4** | 3,035.9 | 14.5 |
| | | | |
| Natural gas revenues | **1,498.4** | 1,199.5 | 298.9 |
| Cost of natural gas sold | **906.5** | 595.2 | (311.3) |
| Total natural gas margins | **591.9** | 604.3 | (12.4) |
| | | | |
| Total electric and natural gas margins | **3,642.3** | 3,640.2 | 2.1 |
| | | | |
| Other operation and maintenance | **1,455.2** | 1,476.7 | 21.5 |
| Depreciation and amortization | **726.9** | 674.5 | (52.4) |
| Property and revenue taxes | **150.9** | 156.2 | 5.3 |
| Operating income | **1,309.3** | 1,332.8 | (23.5) |
| | | | |
| Other income, net | **73.9** | 52.8 | 21.1 |
| Interest expense | **555.6** | 561.3 | 5.7 |
| Income before income taxes | **827.6** | 824.3 | 3.3 |
| | | | |
| Income tax expense | **119.9** | 132.7 | 12.8 |
| Preferred stock dividends of subsidiary | **1.2** | 1.2 | — |
| **Net income attributed to common shareholders** | **$ 706.5** | $ 690.4 | $ 16.1 |

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

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions)*** | **2021** | **2020** | **B (W)** |
| Operation and maintenance not included in line items below | **$ 671.2** | $ 673.5 | $ 2.3 |
| Transmission [1] | **511.1** | 518.0 | 6.9 |
| Regulatory amortizations and other pass through expenses [2] | **141.6** | 138.6 | (3.0) |
| We Power [3] | **114.9** | 119.3 | 4.4 |
| Earnings sharing mechanisms [4] | **5.8** | 21.6 | 15.8 |
| Other | **10.6** | 5.7 | (4.9) |
| **Total other operation and maintenance** | **$ 1,455.2** | $ 1,476.7 | $ 21.5 |

(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 2021 and 2020, $503.6 million and $481.8 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 2021 and 2020, $113.1 million and $115.1 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) See Note 26, Regulatory Environment, for more information about our earnings sharing mechanisms.

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)*** | **2021** | **2020** | **B (W)** |
| **Customer class** | | | |
| Residential | **11,460.1** | 11,523.8 | (63.7) |
| Small commercial and industrial (1) | **12,785.1** | 12,250.0 | 535.1 |
| Large commercial and industrial (1) | **12,406.4** | 11,661.8 | 744.6 |
| Other | **147.6** | 158.7 | (11.1) |
| Total retail (1) | **36,799.2** | 35,594.3 | 1,204.9 |
| Wholesale | **2,862.5** | 3,088.4 | (225.9) |
| Resale | **4,869.2** | 6,189.9 | (1,320.7) |
| **Total sales in MWh (1)** | **44,530.9** | 44,872.6 | (341.7) |

(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)*** | **2021** | **2020** | **B (W)** |
| **Customer class** | | | |
| Residential | **1,036.7** | 1,090.8 | (54.1) |
| Commercial and industrial | **634.0** | 656.7 | (22.7) |
| Total retail | **1,670.7** | 1,747.5 | (76.8) |
| Transport | **1,392.6** | 1,357.7 | 34.9 |
| **Total sales in therms** | **3,063.3** | 3,105.2 | (41.9) |

| | Year Ended December 31 | | |
|---|---|---|---|
| **Weather *(Degree Days)*** | **2021** | **2020** | **B (W)** |
| **WE and WG (1)** | | | |
| Heating (6,548 normal) | **5,735** | 6,092 | (5.9)% |
| Cooling (755 normal) | **1,061** | 938 | 13.1 % |
| | | | |
| **WPS (2)** | | | |
| Heating (7,380 normal) | **6,735** | 7,139 | (5.7)% |
| Cooling (532 normal) | **643** | 660 | (2.6)% |
| | | | |
| **UMERC (3)** | | | |
| Heating (8,398 normal) | **7,744** | 8,189 | (5.4)% |
| Cooling (342 normal) | **428** | 425 | 0.7 % |

(1) Normal degree days are based on a 20-year moving average of monthly temperatures from Mitchell International Airport in Milwaukee, Wisconsin.

(2) Normal degree days are based on a 20-year moving average of monthly temperatures from the Green Bay, Wisconsin weather station.

(3) Normal degree days are based on a 20-year moving average of monthly temperatures from the Iron Mountain, Michigan weather station.

### *Electric Revenues*

Electric revenues increased $264.6 million during 2021, compared with 2020. To the extent that changes in fuel and purchased power costs are passed through to customers, the changes are offset by comparable changes in revenues. See the discussion of electric utility margins below for more information related to recovery of fuel and purchased power costs and the remaining drivers of the changes in electric revenues.

### Electric Utility Margins

Electric utility margins at the Wisconsin segment increased $14.5 million during 2021, compared with 2020. Margins did not change significantly from the PSCW-approved Wisconsin rate orders as the positive impact of increased rates was more than offset by a $27.6 million negative impact related to unprotected excess deferred taxes, which we agreed to return to customers over two years and is offset in income taxes. See Note 26, Regulatory Environment, for more information.

The significant factors impacting the higher electric utility margins were:

- A $50.0 million increase in margins related to higher retail sales volumes, including the impact of weather. Commercial and industrial retail sales volumes improved during 2021, compared with 2020, primarily due to the continued economic recovery in Wisconsin from the COVID-19 pandemic.

- A $19.4 million increase in margins from other revenues, primarily related to higher revenues from third party use of our assets as well as higher late payment charges during 2021. Our Wisconsin utilities resumed charging late payment charges in late August 2020 after they were suspended by the PSCW beginning March 24, 2020, as a result of the COVID-19 pandemic. See Note 26, Regulatory Environment, for more information.

- Securitization revenues of $7.7 million received during 2021 related to an environmental control charge from WE's retail electric distribution customers. We began assessing this charge in June 2021, subsequent to the issuance of the ETBs by WEPCo Environmental Trust in May 2021, in accordance with a November 2020 PSCW financing order. See Note 14, Long-Term Debt, and Note 23, Variable Interest Entities, for more information. These revenues are offset in depreciation and amortization as well as interest expense.

- A $4.1 million increase in margins related to the iron ore mine located in the Upper Peninsula of Michigan. The mine temporarily ceased operations for the second quarter of 2020 as a result of the COVID-19 pandemic.

These increases in margins were partially offset by:

- A $43.3 million year-over-year negative impact from collections of fuel and purchased power costs compared with costs approved in rates. Under the Wisconsin fuel rules, the margins of our electric utilities are impacted by under- or over-collections of certain fuel and purchased power costs that are within a 2% price variance from the costs included in rates, and the remaining variance beyond the 2% price variance is generally deferred for future recovery or refund to customers. In 2021, WPS was unable to defer its portion of the under-collected fuel and purchased power costs due to earning an ROE in excess of the PSCW authorized amount.

- Lower margins of $23.9 million driven by a decrease in wholesale customers related to the expiration of certain wholesale contracts.

### Natural Gas Revenues

Natural gas revenues increased $298.9 million during 2021, compared with 2020. Because prudently incurred natural gas costs are passed through to our customers in current rates, the changes are offset by comparable changes in revenues. The average per-unit cost of natural gas increased 53.6% during 2021, compared with 2020. The remaining drivers of changes in natural gas revenues are described in the discussion of natural gas utility margins below.

### Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment decreased $12.4 million during 2021, compared with 2020. The most significant factor impacting the lower natural gas utility margins was a $15.4 million decrease from lower retail sales volumes, including the impact of weather. This decrease in margins was partially offset by a $3.1 million increase from other revenues, primarily related to higher late payment charges during 2021, compared with 2020, as discussed above under Electric Utility Margins.

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

Other operating expenses at the Wisconsin segment increased $25.6 million during 2021, compared with 2020. The significant factors impacting the increase in other operating expenses were:

- A $52.4 million increase in depreciation and amortization, driven by assets being placed into service as we continue to execute on our capital plan as well as an increase related to the We Power leases. In addition, a portion of the increase is related to securitization amortization, which is offset in revenues.

- A $26.2 million increase in electric and natural gas distribution expenses, primarily driven by significant storms in 2021.

- A $15.3 million increase in expenses related to charitable projects supporting our customers and the communities within our service territories.

- An $11.2 million increase in customer service expenses, primarily related to additional costs from an information technology project created to improve the billing, call center, and credit collection functions, as well as higher call volumes and metering costs.

These increases in other operating expenses were partially offset by:

- A $21.9 million net decrease in operating expense related to our power plants, primarily driven by reduced costs at the OCPP.

- A $19.6 million decrease in benefit costs, primarily due to lower stock-based compensation.

- A $15.8 million decrease in expense related to the earnings sharing mechanisms in place at our Wisconsin utilities. See Note 26, Regulatory Environment, for more information.

- A $12.5 million decrease in costs incurred related to facility damage to our PSB resulting from a significant rain event in May 2020. See Note 7, Property, Plant, and Equipment, for more information on the significant rain event.

- A $6.9 million decrease in transmission expense driven by a decrease in electric wholesale customers related to the expiration of certain wholesale contracts.

### *Other Income, Net*

Other income, net at the Wisconsin segment increased $21.1 million during 2021, compared with 2020, driven by higher net credits from the non-service components of our net periodic pension and OPEB costs. See Note 20, Employee Benefits, for more information on our benefit costs.

### *Interest Expense*

Interest expense at the Wisconsin segment decreased $5.7 million during 2021, compared with 2020, driven by lower interest expense on finance lease liabilities, primarily related to the We Power leases, as finance lease liabilities decrease each year as payments are made. Lower interest expense on short-term debt was also a contributor as commercial paper rates were lower in 2021 compared to 2020. These decreases in interest expense were partially offset by interest expense on the ETBs issued by WEPCo Environmental Trust in May 2021, which is offset in revenues.

### *Income Tax Expense*

Income tax expense at the Wisconsin segment decreased $12.8 million during 2021, compared with 2020. The decrease was primarily due to an approximate $27.6 million positive impact related to the 2021 amortization of the unprotected excess deferred tax benefits from the Tax Legislation in connection with the Wisconsin rate orders approved by the PSCW, effective January 1, 2020. The impact due to the benefit from the amortization of the unprotected excess deferred tax benefits from the Tax Legislation did not impact earnings as there was an offsetting negative impact in operating income. Partially offsetting this decrease in income tax expense was a decrease in PTCs and an increase in pretax income. See Note 16, Income Taxes, and Note 26, Regulatory Environment, 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, 2021 was $223.0 million, representing a $19.5 million, or 9.6%, increase over the prior year. The increase was driven by higher natural gas margins due to PGL's continued capital investment in the SMP project under its QIP rider and an increase in late payment charges. Lower benefit costs also contributed to the increase in earnings. These positive impacts were partially offset by higher depreciation expense and an increase in natural gas distribution and maintenance costs during 2021.

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

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions)*** | **2021** | **2020** | **B (W)** |
| Natural gas revenues | **$ 1,672.8** | $ 1,321.9 | $ 350.9 |
| Cost of natural gas sold | **628.4** | 330.9 | (297.5) |
| Total natural gas margins | **1,044.4** | 991.0 | 53.4 |
| | | | |
| Other operation and maintenance | **433.5** | 435.4 | 1.9 |
| Depreciation and amortization | **218.1** | 196.7 | (21.4) |
| Property and revenue taxes | **31.2** | 28.1 | (3.1) |
| Operating income | **361.6** | 330.8 | 30.8 |
| | | | |
| Other income, net | **7.3** | 2.3 | 5.0 |
| Interest expense | **66.6** | 63.5 | (3.1) |
| Income before income taxes | **302.3** | 269.6 | 32.7 |
| | | | |
| Income tax expense | **79.3** | 66.1 | (13.2) |
| **Net income attributed to common shareholders** | **$ 223.0** | $ 203.5 | $ 19.5 |

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

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions)*** | **2021** | **2020** | **B (W)** |
| Operation and maintenance not included in the line items below | **$ 320.3** | $ 332.1 | $ 11.8 |
| Riders [(1)] | **112.1** | 101.4 | (10.7) |
| Regulatory amortizations [(1)] | **(1.5)** | (2.6) | (1.1) |
| Other | **2.6** | 4.5 | 1.9 |
| **Total other operation and maintenance** | **$ 433.5** | $ 435.4 | $ 1.9 |

[(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:

| | Year Ended December 31 | | |
|---|---|---|---|
| **Natural Gas Sales Volumes *(Therms - in millions)*** | **2021** | **2020** | **B (W)** |
| **Customer Class** | | | |
| Residential | **819.2** | 832.6 | (13.4) |
| Commercial and industrial | **319.5** | 326.1 | (6.6) |
| Total retail | **1,138.7** | 1,158.7 | (20.0) |
| Transport | **760.1** | 785.7 | (25.6) |
| **Total sales in therms** | **1,898.8** | 1,944.4 | (45.6) |

| Weather *(Degree Days)* [1] | Year Ended December 31 2021 | 2020 | B (W) |
|---|---|---|---|
| Heating (6,071 normal) | **5,468** | 5,597 | (2.3)% |

[1] Normal heating degree days are based on a 12-year moving average of monthly temperatures from Chicago's O'Hare Airport.

### *Natural Gas Revenues*

Natural gas revenues increased $350.9 million during 2021, compared with 2020. Because prudently incurred natural gas costs are passed through to our customers in current rates, the changes are offset by comparable changes in revenues. The average per-unit cost of natural gas sold increased 95.5% during 2021, compared with 2020. The remaining drivers of changes in natural gas revenues are described in the discussion of margins below.

### *Natural Gas Utility Margins*

Natural gas utility margins at the Illinois segment, net of the $10.7 million impact of the riders referenced in the table above, increased $42.7 million during 2021, compared with 2020. The increase in margins was primarily driven by:

- A $25.5 million increase in revenues at PGL due to continued capital investment in the SMP project. PGL recovers the costs related to the SMP through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023.

- A $7.5 million increase in late payment charges driven by the reinstatement of late payment charges during 2021 that were suspended by the ICC in 2020 due to the COVID-19 pandemic.

- A $3.6 million increase in the invested capital tax adjustment rider related to higher plant placed in service during 2021 compared with 2020, which did not impact net income as it was offset in property and revenue taxes. The invested capital tax adjustment rider is a mechanism that allows PGL and NSG to recover (or refund) the difference between the cost of invested capital tax incurred and the amount collected through base rates.

- A $3.1 million increase related to the collection of fixed charges driven by the expiration of the moratorium on disconnections during 2020 due to a regulatory order from the ICC in response to the COVID-19 pandemic.

- A $1.9 million increase related to the impact of the NSG rate order approved by the ICC, effective September 15, 2021.

See Note 26, Regulatory Environment, for more information.

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

Other operating expenses at the Illinois segment increased $11.9 million, net of the impact of the riders referenced in the table above, during 2021, compared with 2020. The significant factors impacting the increase in operating expenses were:

- A $21.4 million increase in depreciation expense, primarily driven by PGL's continued capital investment in the SMP project.

- A $16.4 million increase in natural gas distribution and maintenance costs, primarily related to maintaining the natural gas infrastructure, including costs associated with maintenance at our gas storage field.

These increases in operating expenses were partially offset by:

- A $23.1 million decrease in benefit costs, primarily due to lower costs related to pension, stock-based compensation, and severance.

- A $2.8 million decrease in costs associated with the investigation and remediation of the natural gas leak at the Manlove Gas Storage Field. See Part I, Item 3. Legal Proceedings, for more information.

### *Other Income, Net*

Other income, net at the Illinois segment increased $5.0 million during 2021, compared with 2020, driven by higher net credits from the non-service components of our net periodic pension and OPEB costs. See Note 20, Employee Benefits, for more information on our benefit costs.

### *Interest Expense*

Interest expense at the Illinois segment increased $3.1 million during 2021, compared with 2020, driven by higher long-term debt balances related to incremental borrowings in both 2021 and 2020, primarily related to additional capital investment.

### *Income Tax Expense*

Income tax expense at the Illinois segment increased $13.2 million during 2021, compared with 2020, driven by an increase in pretax income and a $5.0 million decrease in unrecognized tax benefits compared with 2020. See Note 16, Income Taxes, for more information.

## 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, 2021 was $35.8 million, representing a $3.2 million, or 8.2%, decrease over the prior year. The decrease was driven by higher operating expenses due to depreciation and amortization, and higher operation and maintenance expense, primarily related to the February 2021 cold weather event. These decreases in net income were partially offset by lower interest expense in 2021 due to the deferral of interest expense related to capital investments made by MGU since its last rate case. See Note 26, Regulatory Environment, for more information.

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.

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | **2020** | **B (W)** |
| Natural gas revenues | **$ 519.0** | $ 384.1 | $ 134.9 |
| Cost of natural gas sold | **319.3** | 184.8 | (134.5) |
| Total natural gas margins | **199.7** | 199.3 | 0.4 |
| | | | |
| Other operation and maintenance | **90.4** | 87.0 | (3.4) |
| Depreciation and amortization | **38.1** | 33.5 | (4.6) |
| Property and revenue taxes | **18.8** | 17.2 | (1.6) |
| Operating income | **52.4** | 61.6 | (9.2) |
| | | | |
| Other income, net | **1.1** | 0.7 | 0.4 |
| Interest expense | **6.2** | 10.2 | 4.0 |
| Income before income taxes | **47.3** | 52.1 | (4.8) |
| | | | |
| Income tax expense | **11.5** | 13.1 | 1.6 |
| **Net income attributed to common shareholders** | **$ 35.8** | $ 39.0 | $ (3.2) |

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

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | **2020** | **B (W)** |
| Operation and maintenance not included in line items below | **$ 70.5** | $ 67.9 | $ (2.6) |
| Regulatory amortizations and other pass through expenses [1] | **19.8** | 18.9 | (0.9) |
| Other | **0.1** | 0.2 | 0.1 |
| **Total other operation and maintenance** | **$ 90.4** | $ 87.0 | $ (3.4) |

[(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 volumes by customer class and weather statistics:

| | Year Ended December 31 | | |
|---|---|---|---|
| **Natural Gas Sales Volumes (*Therms - in millions)*** | **2021** | **2020** | **B (W)** |
| **Customer Class** | | | |
| Residential | **301.1** | 309.6 | (8.5) |
| Commercial and industrial | **188.5** | 200.5 | (12.0) |
| Total retail | **489.6** | 510.1 | (20.5) |
| Transportation | **801.6** | 728.5 | 73.1 |
| **Total sales in therms** | **1,291.2** | 1,238.6 | 52.6 |

| | Year Ended December 31 | | |
|---|---|---|---|
| **Weather *(Degree Days)*** [(1)] | **2021** | **2020** | **B (W)** |
| **MERC** | | | |
| Heating (7,969 normal) | **7,440** | 7,896 | (5.8)% |
| | | | |
| **MGU** | | | |
| Heating (6,209 normal) | **5,755** | 5,952 | (3.3)% |

[(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 temperatures from various weather stations throughout their respective territories.

### *Natural Gas Revenues*

Natural gas revenues increased $134.9 million during 2021, compared with 2020. Because prudently incurred natural gas costs are passed through to our customers in current rates, the changes are offset by comparable changes in revenues. The average per-unit cost of natural gas sold increased 83.8% during 2021, compared with 2020. The remaining drivers of changes in natural gas revenues are described in the discussion of margins below.

### *Natural Gas Utility Margins*

Natural gas utility margins increased $0.4 million during 2021, compared with 2020. This was primarily driven by a $3.7 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. This increase was partially offset by a $1.9 million decrease related to lower sales volumes and a $1.0 million decrease associated with lower revenues related to MERC's GUIC rider. The GUIC rider allows MERC to recover previously approved GUIC incurred to replace or modify natural gas facilities to the extent the work is required by state, federal, or other government agencies and exceeds the costs included in base rates.

### *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 $9.6 million during 2021, compared with 2020. The significant factors impacting the increase in operating expenses were:

- A $4.6 million increase in depreciation and amortization related to continued capital investment.
- A $3.7 million increase in operation and maintenance expense due to MERC's CIP program, which has an offsetting increase in margins.
- A $3.0 million increase in operation and maintenance expense related to the February 2021 cold weather event.

These increases in operating expenses were partially offset by:

- A $1.9 million decrease in operation and maintenance expense related to effective cost control.

- A $1.8 million decrease in operation and maintenance expense due to MERC's GUIC rider, primarily related to having fewer expenditures in 2021 compared to 2020, which is mostly offset in margins.

### *Interest Expense*

Interest expense at the other states segment decreased $4.0 million during 2021, compared with 2020, driven by the deferral of interest expense related to capital investments made by MGU since its last rate case, as approved by the MPSC. The decrease was partially offset by long term debt issuances in 2020 and 2021, primarily related to continued capital investment. See Note 26, Regulatory Environment, for more information on the MPSC order that allowed MGU to defer interest expense related to certain capital expenditures.

### *Income Tax Expense*

Income tax expense at the other states segment decreased $1.6 million during 2021, compared with 2020, driven by a decrease in pretax income.

## Electric Transmission Segment Contribution to Net Income Attributed to Common Shareholders

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | **2020** | **B (W)** |
| Equity in earnings of transmission affiliates | **$ 158.1** | $ 175.8 | $ (17.7) |
| Other expense | **0.1** | 0.1 | — |
| Interest expense | **19.4** | 19.4 | — |
| Income before income taxes | **138.6** | 156.3 | (17.7) |
| | | | |
| Income tax expense | **32.3** | 43.7 | 11.4 |
| **Net income attributed to common shareholders** | **$ 106.3** | $ 112.6 | $ (6.3) |

### *Equity in Earnings of Transmission Affiliates*

Equity in earnings of transmission affiliates decreased $17.7 million during 2021, compared with 2020, driven by:

- A $14.6 million decrease in equity earnings related to the impact of the FERC order issued in May 2020 addressing complaints related to ATC's ROE. The order resulted in an increase in the base ROE that ATC is allowed to collect, retroactive to November 2013, which was recorded in 2020. For further discussion of this FERC order, see Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – American Transmission Company Allowed Return on Equity Complaints.

- A $12.2 million decrease in equity earnings related to a goodwill impairment recorded by ATC Holdco, which was formed to invest in transmission-related projects outside of ATC's traditional footprint.

Continued capital investment by ATC partially offset the negative year-over-year impact on equity earnings related to the 2020 FERC order and the goodwill impairment recorded at ATC Holdco.

### *Income Tax Expense*

Income tax expense at the electric transmission segment decreased $11.4 million during 2021, compared with 2020, driven by a $6.6 million positive impact of uncertain tax positions in 2021 that were recorded in 2020 and a $4.7 million positive impact related to a decrease in pretax income.

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

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | **2020** | **B (W)** |
| Operating income | **$ 350.3** | $ 366.3 | $ (16.0) |
| | | | |
| Other income, net | **—** | 0.3 | (0.3) |
| Interest expense | **71.0** | 60.8 | (10.2) |
| Income before income taxes | **279.3** | 305.8 | (26.5) |
| | | | |
| Income tax expense | **3.1** | 44.7 | 41.6 |
| Net (income) loss attributed to noncontrolling interests | **3.0** | (0.3) | 3.3 |
| **Net income attributed to common shareholders** | **$ 279.2** | $ 260.8 | $ 18.4 |

#### *Operating Income*

Operating income at the non-utility energy infrastructure segment decreased $16.0 million during 2021, compared with 2020. The decrease was primarily driven by an aggregate of $21.9 million of higher operating losses at our Coyote Ridge wind park and 2021 operating losses at our Tatanka Ridge wind park related to congestion on the electricity grid due, in part, to several transmission outages in 2021. This decrease was partially offset by higher operating income of $6.6 million at our Blooming Grove wind park that achieved commercial operation in December 2020.

#### *Interest Expense*

Interest expense at the non-utility energy infrastructure segment increased $10.2 million during 2021, compared with 2020, primarily due to WECI Wind Holding I's debt issuance in December 2020.

#### *Income Tax Expense*

Income tax expense at the non-utility energy infrastructure segment decreased $41.6 million during 2021, compared with 2020, primarily due to a $34.0 million increase in PTCs generated in 2021, driven by our Blooming Grove and Tatanka Ridge wind parks that achieved commercial operation in December 2020 and January 2021, respectively, and lower pretax earnings.

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

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | **2020** | **B (W)** |
| Operating loss | **$ (18.9)** | $ (40.8) | $ 21.9 |
| | | | |
| Other income, net | **51.7** | 24.4 | 27.3 |
| Interest expense | **92.8** | 124.0 | 31.2 |
| Loss on debt extinguishment | **36.3** | 38.4 | 2.1 |
| Loss before income taxes | **(96.3)** | (178.8) | 82.5 |
| | | | |
| Income tax benefit | **(45.8)** | (72.4) | (26.6) |
| **Net loss attributed to common shareholders** | **$ (50.5)** | $ (106.4) | $ 55.9 |

#### *Operating Loss*

The operating loss at the corporate and other segment decreased $21.9 million during 2021, compared with 2020, driven by:

- A $17.2 million positive impact from the change in operating income at Wispark. The change was driven by reductions in the carrying value of certain real estate-related assets during 2020, which did not reoccur in 2021, resulting in a positive year-over-year variance.

- A $4.7 million positive impact due to a pre-tax loss recorded in 2020 on the sale of a portfolio of residential solar facilities owned by PDL. The sale resulted in an after-tax gain; however, the gain related to the recognition of deferred ITCs, which were included as a reduction of income tax expense on our income statement. See Note 3, Dispositions, for more information on the sale.

### *Other Income, Net*

Other income, net at the corporate and other segment increased $27.3 million during 2021, compared with 2020, driven by a $17.6 million increase in earnings from our equity method investments in technology and energy-focused investment funds. Higher net gains from the investments held in the Integrys rabbi trust of $5.9 million also contributed to the increase. The gains from the investments held in the rabbi trust partially offset higher benefits costs related to deferred compensation, which are included in other operation and maintenance expense in our operating 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 decreased $31.2 million during 2021, compared with 2020, as we opportunistically refinanced long-term debt obligations in both 2021 and 2020 in order to take advantage of lower interest rates. Lower interest expense on short-term debt was also a contributor as commercial paper rates were lower in 2021 compared to 2020.

### *Loss on Debt Extinguishment*

The loss on debt extinguishment decreased $2.1 million, driven by a decrease in make whole payments associated with refinancing debt obligations prior to maturity in 2021, compared to 2020.

### *Income Tax Benefit*

The income tax benefit at the corporate and other segment decreased $26.6 million during 2021, compared with 2020, driven by a lower pretax loss. Also contributing to the decrease in the income tax benefit were a $9.1 million decrease in excess tax benefits recognized on stock option exercises and a $6.5 million negative impact from the recognition in 2020 of previously deferred ITCs related to the sale of PDL's residential solar facilities. See Note 3, Dispositions, for more information on the sale of residential solar facilities. These decreases in the income tax benefit were partially offset by an $11.8 million change in unrecognized tax benefits during 2021, compared with 2020. See Note 16, Income Taxes, for more information.

## 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, 2021 with the year ended December 31, 2020. For a similar discussion that compares our cash flows for the year ended December 31, 2020 with the year ended December 31, 2019, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources in Part II of our 2020 Annual Report on Form 10-K, which was filed with the SEC on February 25, 2021.

## Cash Flows

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

| *(in millions)* | 2021 | 2020 | Change in 2021 Over 2020 |
|---|---|---|---|
| **Cash provided by (used in):** | | | |
| Operating activities | **$ 2,032.7** | $ 2,196.0 | $ (163.3) |
| Investing activities | **(2,311.8)** | (2,806.8) | 495.0 |
| Financing activities | **294.0** | 601.1 | (307.1) |

### *Operating Activities*

Net cash provided by operating activities decreased $163.3 million during 2021, compared with 2020. The increase in cash earnings was more than offset by working capital requirements, primarily related to higher natural gas prices, as discussed in more detail below.

The significant factors impacting the decrease in net cash provided by operating activities include:

- A $240.0 million decrease in cash related to higher payments for fuel and purchased power at our plants during 2021, compared with 2020. We incurred higher natural gas costs throughout 2021, compared with 2020, as a result of an increase in the price of natural gas. Increased coal costs also drove higher payments for fuel used at our plants.

- A $221.7 million decrease in cash from higher payments for operating and maintenance expenses. During 2021, our payments were higher for storm restoration, transmission, electric and natural gas distribution and maintenance, charitable projects, and customer service.

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

- A $208.8 million increase in cash due to realized gains on derivative instruments as well as higher collateral received from counterparties during 2021, both driven by higher natural gas prices.

- A $46.9 million increase in cash related to a decrease in contributions and payments related to pension and OPEB plans during 2021, compared with 2020.

- A $30.7 million increase in cash related to higher overall collections from customers as a result of an increase in sales volumes during 2021, compared with 2020. This increase was driven by favorable weather and the continued economic recovery in Wisconsin from the COVID-19 pandemic. In addition, we continued to recover natural gas costs from our customers related to the extreme weather conditions that occurred in February 2021 in accordance with various orders from our commissions. See Note 26, Regulatory Environment, for more information on the recovery of these natural gas costs.

### *Investing Activities*

Net cash used in investing activities decreased $495.0 million during 2021, compared with 2020, driven by:

- The acquisition of a 90% ownership interest in Blooming Grove in December 2020 for $364.6 million, which is net of restricted cash acquired of $24.1 million. See Note 2, Acquisitions, for more information.

- The acquisition of an 85% ownership interest in Tatanka Ridge in December 2020 for $239.9 million. See Note 2, Acquisitions, for more information.

- Capital contributions paid to transmission affiliates of $21.2 million during 2020. See Note 21, Investment in Transmission Affiliates, for more information. There were no payments to transmission affiliates during 2021.

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

- The acquisition of a 90% ownership interest in Jayhawk in February 2021 for $119.9 million. See Note 2, Acquisitions, for more information.

- Insurance proceeds received of $23.2 million for property damage during 2020, primarily driven by proceeds received for the PSB claim. See Note 7, Property, Plant, and Equipment, for more information.

- A $14.0 million increase in cash paid for capital expenditures during 2021, compared with 2020, which is discussed in more detail below.

**Capital Expenditures**

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

| **Reportable Segment *(in millions)*** | **2021** | **2020** | **Change in 2021 Over 2020** |
|---|---|---|---|
| Wisconsin | **$ 1,389.7** | $ 1,382.4 | $ 7.3 |
| Illinois | **533.7** | 652.7 | (119.0) |
| Other states | **95.9** | 144.3 | (48.4) |
| Non-utility energy infrastructure | **215.4** | 26.3 | 189.1 |
| Corporate and other | **18.1** | 33.1 | (15.0) |
| **Total capital expenditures** | **$ 2,252.8** | $ 2,238.8 | $ 14.0 |

The increase in cash paid for capital expenditures at the Wisconsin segment during 2021, compared with 2020, was primarily driven by higher capital expenditures related to upgrades to WE's natural gas distribution system, repairs and restoration of WE's PSB as a result of the significant rain event in May 2020, and construction activity at Crane Creek, Badger Hollow II, and the LNG facilities during 2021. See Note 7, Property, Plant, and Equipment, for more information on the PSB. These increases were partially offset by lower payments for capital expenditures related to Badger Hollow I, Two Creeks, an information technology project created to improve the billing, call center, and credit collection functions, upgrades of WPS's automated meter reading devices, and upgrades to WG's gas distribution system during 2021.

The decrease in cash paid for capital expenditures at the Illinois segment during 2021, compared with 2020, was primarily driven by lower payments for capital expenditures related to facilities projects, upgrades at the Manlove Gas Storage Field, and upgrades to the natural gas distribution system during 2021.

The decrease in cash paid for capital expenditures at the other states segment during 2021, compared with 2020, was primarily driven by a decrease in installations of automated meter reading devices during 2021.

The increase in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2021, compared with 2020, was primarily driven by the construction of Jayhawk, which was acquired in February 2021 and became commercially operational in December 2021. See Note 2, Acquisitions, for more information.

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

### *Financing Activities*

Net cash provided by financing activities decreased $307.1 million during 2021, compared with 2020, driven by:

- A $680.0 million decrease in cash due to a $340.0 million repayment of a 364-day term loan during 2021, compared with its issuance during 2020, to enhance our liquidity position in response to the COVID-19 pandemic.

- A $146.9 million decrease in cash due to lower net borrowings of commercial paper during 2021, compared with 2020.

- A $56.8 million decrease in cash due to higher dividends paid on our common stock during 2021, compared with 2020. In January 2021, our Board of Directors increased our quarterly dividend by $0.045 per share (7.1%) effective with the March 2021 dividend payment.

- A $28.1 million decrease in cash from fewer stock options exercised during 2021, compared with 2020.

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

- A $506.6 million increase in cash related to lower long-term debt repayments during 2021, compared with 2020.

- A $66.1 million increase in cash due to a decrease in the number and cost of shares of our common stock purchased during 2021, compared with 2020, to satisfy requirements of our stock-based compensation plans.

- The acquisition of an additional 10% ownership interest in Upstream in April 2020 for $31.0 million. See Note 2, Acquisitions, for more information.

**Significant Financing Activities**

For more information on our financing activities, see 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 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 requirements, regulatory restraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, economic trends, supply chain disruptions, the COVID-19 pandemic, 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)* | 2022 | 2023 | 2024 |
|---|---|---|---|
| Wisconsin | $ 2,131.7 | $ 2,148.0 | $ 2,114.1 |
| Illinois | 573.1 | 586.8 | 635.0 |
| Other states | 119.1 | 103.6 | 106.4 |
| Non-utility energy infrastructure | 870.8 | 325.7 | 297.5 |
| Corporate and other | 22.0 | 17.5 | 4.3 |
| **Total** | $ 3,716.7 | $ 3,181.6 | $ 3,157.3 |

WE, WPS, and WG continue to upgrade their electric and natural gas distribution systems to enhance reliability. These upgrades include the AMI program. AMI is an integrated system of smart meters, communication networks, and data management systems that enable two-way communication between utilities and customers.

We are committed to investing in solar, wind, battery storage, and clean natural gas-fired generation. Below are examples of projects that are proposed or currently underway.

- We have received approval to invest in 100 MW of utility-scale solar within our Wisconsin segment. WE has partnered with an unaffiliated utility to construct a solar project, Badger Hollow II, that will be located in Iowa County, Wisconsin. Once constructed, WE will own 100 MW of this project. WE's share of the cost of this project is estimated to be $130 million. Commercial operation of Badger Hollow II is targeted for the first quarter of 2023.

- In February 2021, WE and WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire and construct the Paris Solar-Battery Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Kenosha County, Wisconsin and once constructed, WE and WPS will collectively own

180 MW of solar generation and 99 MW of battery storage of this project. If approved, WE's and WPS's combined share of the cost of this project is estimated to be approximately $385 million, with construction expected to be completed by the end of 2023.

- WE and WPS have received approval to accelerate capital investments in two wind parks. The investment is expected to be approximately $154 million to repower major components of Blue Sky and Crane Creek, which are expected to be completed by the end of 2022.

- In March 2021, WE and WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire and construct the Darien Solar-Battery Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Rock and Walworth counties, Wisconsin and once constructed, WE and WPS will collectively own 225 MW of solar generation and 68 MW of battery storage of this project. If approved, WE's and WPS's combined share of the cost of this project is estimated to be approximately $400 million, with construction expected to be completed by the end of 2023.

- WPS, along with an unaffiliated utility, received PSCW approval to acquire the Red Barn Wind Park, a utility-scale wind-powered electric generating facility. The project will be located in Grant County, Wisconsin and once constructed, WPS will own 82 MW of this project. WPS's share of the cost of this project is estimated to be $150 million, with construction expected to be completed by the end of 2022.

- In April 2021, WE and WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire the Koshkonong Solar-Battery Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Dane County, Wisconsin and once constructed, WE and WPS will collectively own 270 MW of solar generation and 149 MW of battery storage of this project. If approved, WE's and WPS's combined share of the cost of this project is estimated to be approximately $585 million, with construction expected to be completed by the second quarter of 2024.

- In April 2021, WE and WPS filed an application with the PSCW for approval to construct 128 MW of natural gas-fired generation at WPS's existing Weston power plant site in northern Wisconsin. The new facility will consist of seven reciprocating internal combustion engines. If approved, we estimate the cost of this project to be approximately $170 million, with construction expected to be completed by the end of 2023.

- In November 2021, WE and WPS signed an asset purchase agreement to acquire Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electrical generation facility in Whitewater, Wisconsin. In December 2021, WE and WPS filed an application with the PSCW for approval to acquire Whitewater. If approved, the cost of this facility will be $72.7 million, with the transaction expected to close in January 2023. See Note 15, Leases, for more information.

- In January 2022, WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire a portion of West Riverside's nameplate capacity. WPS is also requesting approval to assign the option to purchase part of West Riverside to WE. If approved, WPS or WE would acquire 100 MW of capacity, in the first of two potential option exercises. West Riverside is a new, combined-cycle natural gas plant recently completed by an unaffiliated utility in Rock County, Wisconsin. If approved, our share of the cost of this ownership interest is approximately $91 million, with the transaction expected to close in the second quarter of 2023.

WE and WG have received PSCW approval to each construct its own LNG facility. Each facility would provide approximately one Bcf of natural gas supply to meet anticipated peak demand without requiring the construction of additional interstate pipeline capacity. These facilities are expected to reduce the likelihood of constraints on WE's and WG's natural gas systems during the highest demand days of winter. The total cost of both projects is estimated to be approximately $370 million, with approximately half being invested by each utility. Commercial operation of the WE and WG LNG facilities are targeted for the end of 2023 and 2024, respectively.

PGL is continuing work on the SMP, a project under which PGL is replacing approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023. PGL's projected average annual investment through 2024 is between $280 million and $300 million. See Note 26, Regulatory Environment, for more information on the SMP.

The non-utility energy infrastructure segment line item in the table above includes WECI's planned investment in Thunderhead and Sapphire Sky. See Note 2, Acquisitions, for more information on these wind projects.

We expect to provide total capital contributions to ATC (not included in the above table) of approximately $115 million from 2022 through 2024. We do not expect to make any contributions to ATC Holdco during that period.

See Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Withhold Release Order Related to Silica-Based Products for information on the potential impacts to our solar projects as a result of CBP actions related to solar panels.

### *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 over the next five years. The following table summarizes our required interest payments on long-term debt (excluding finance lease obligations) as of December 31, 2021:

| | Interest Payments Due by Period | | | | |
|---|---|---|---|---|---|
| ***(in millions)*** | **Total** | **Less Than 1 Year** | **1-3 Years** | **3-5 Years** | **More Than 5 Years** |
| Interest payments on long-term debt [1] | $ 7,563.2 | $ 456.5 | $ 892.6 | $ 810.8 | $ 5,403.3 |

[1] The interest due on our variable rate debt is based on the interest rates that were in effect on December 31, 2021.

### *Common Stock Dividends*

On January 20, 2022, our Board of Directors increased our quarterly dividend to $0.7275 per share effective with the first quarter of 2022 dividend payment, an increase of 7.4%. This equates to an annual dividend of $2.91 per share. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

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 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 | $ 465.3 | $ 243.8 | $ 178.0 | $ 39.8 | $ 3.7 |

We have various finance and operating lease obligations. Our finance lease obligations primarily relate to power purchase commitments and land leases for our solar 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 2022 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, 2021 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 24, Commitments and Contingencies, and Note 16, Income Taxes, 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. For additional information, see Note 13, Short-Term Debt and Lines of Credit, Note 19, Guarantees, and Note 23, Variable Interest Entities.

## 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, which allows us to obtain external short-term borrowings, including commercial paper and term loans, and intermediate or long-term debt securities. 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.

See Factors Affecting Results, Liquidity, and Capital Resources – Coronavirus Disease – 2019, for additional information on the impacts of the COVID-19 pandemic on our liquidity.

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 2022, 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, 2021, our current liabilities exceeded our current assets by $1,096.3 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 of $1,201.6 million 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 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt, for more information about our 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, 2021, these trusts had investments of approximately $4.3 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, 2021 and 2020, as well as an adjusted capitalization structure that we believe is consistent with how a majority of the rating agencies currently view our 2007 Junior Notes:

| | 2021 | | 2020 | |
|---|---|---|---|---|
| ***(in millions)*** | **Actual** | **Adjusted** | **Actual** | **Adjusted** |
| Common shareholders' equity | **$ 10,913.2** | **$ 11,163.2** | $ 10,469.7 | $ 10,719.7 |
| Preferred stock of subsidiary | **30.4** | **30.4** | 30.4 | 30.4 |
| Long-term debt (including current portion) | **13,693.1** | **13,443.1** | 12,513.9 | 12,263.9 |
| Short-term debt | **1,897.0** | **1,897.0** | 1,776.9 | 1,776.9 |
| **Total capitalization** | **$ 26,533.7** | **$ 26,533.7** | $ 24,790.9 | $ 24,790.9 |
| Total debt | **$ 15,590.1** | **$ 15,340.1** | $ 14,290.8 | $ 14,040.8 |
| Ratio of debt to total capitalization | **58.8 %** | **57.8 %** | 57.6 % | 56.6 % |

Included in long-term debt on our balance sheets as of December 31, 2021 and 2020, is $500.0 million principal amount of the 2007 Junior Notes. The adjusted presentation attributes $250.0 million of the 2007 Junior Notes to common shareholders' equity and $250.0 million to long-term debt.

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 2007 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*

At December 31, 2021, we were in compliance with all 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 13, Short-Term Debt and Lines of Credit, Note 14, Long-Term Debt, and Note 11, Common Equity, 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, 2021. 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, 2021, it could have been required to post $100 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 September 2021, Moody's changed the rating outlook for WG to negative from stable as a result of the decision to defer its next base rate case to 2022. The change in rating outlook has not had, and we do not believe that it will have, a material impact on our ability to access capital markets. Moody's affirmed WG's ratings including its A3 senior unsecured rating and its P-2 short term rating for commercial paper. See Note 26, Regulatory Environment, for more information on the rate case delay.

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

### Coronavirus Disease – 2019

The COVID-19 pandemic has adversely impacted the economy and financial markets, which has adversely affected our business. During 2021, commercial and industrial retail sales volumes began to improve due to the continued economic recovery in our service territories. However, there are still questions regarding the extent and duration of the COVID-19 pandemic itself. Orders limiting the capacity of various businesses could be adopted again in the future depending on how the virus continues to mutate and spread. The resulting effects of any future orders could have a variety of adverse impacts on us and our subsidiaries, 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.

#### *Liquidity and Financial Markets*

Upon the initial enactment of certain COVID-19 related shelter-in-place orders in early to mid-March 2020, commercial paper markets became more expensive and related terms became less flexible. In response to these signs of market instability, the Federal Reserve implemented certain measures, including a reduction in its benchmark Federal Funds rate and the establishment of various programs to restore liquidity and stability into the short-term funding markets. These measures had an almost immediate mitigating effect on commercial paper rates and availability in 2020. As of December 31, 2021, the disruptions in the commercial paper and long-term debt markets as a result of the COVID-19 pandemic have subsided.

#### *Allowance for Credit Losses*

Economic disruptions caused by the COVID-19 pandemic, including higher unemployment rates and the inability of some businesses to recover from the pandemic, caused a higher percentage of our accounts receivable balances to become uncollectible. Although impacts on our results of operations related to higher uncollectible receivable balances were mitigated by regulatory mechanisms and certain COVID-19 specific regulatory orders we received, the increase in past due receivables we experienced resulted in higher working capital requirements. However, with normal collection practices now underway in all of our service territories, we continue to see an improvement in our past due receivable balances, as evidenced by a decrease in our allowance for credit losses. See Note 5, Credit Losses, for more information.

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. In addition, we have received specific orders related to the deferral of certain costs (including credit losses) and foregone revenues related to the COVID-19 pandemic. The additional protections provided by these COVID-19 specific regulatory orders are still being assessed and will be subject to prudency reviews. See Note 26, Regulatory Environment, for more information on these orders.

### *Loss of Business*

Many of the commercial and industrial customers in our service territories have recovered, or are recovering, from the COVID-19 pandemic. However, we are still seeing a decrease in the consumption of electricity and natural gas by some of our customers as they continue to experience lower demand for their products and services, or are not operating at full capacity. The extent to which the pandemic related decrease in consumption will continue to impact our results of operations and liquidity is dependent upon the duration of the COVID-19 pandemic and the ability of our customers to continue, or to resume, normal operations.

### *Employee Safety*

The health and safety of our employees during the COVID-19 pandemic is paramount and enables us to continue to provide critical services to our customers.

We are taking into consideration CDC guidelines and have taken precautions with regard to employee hygiene and facility cleanliness, imposed travel limitations on our employees, provided additional employee benefits, and implemented remote-work policies where appropriate. We have an incident management team and updated our pandemic continuity plan, which includes identifying critical work groups and ensuring safe-harbor plans are in place. We have minimized the unnecessary risk of exposure to COVID-19 by implementing self-quarantine measures and have adopted additional precautionary measures for our critical work groups.

Additional protocols have been implemented for our field employees who travel to customer premises in order to protect them, our customers, and the public. We have modified our work protocols to ensure compliance with social distancing and face covering recommendations. We are developing return-to-the workplace strategies for those employees currently working remotely, taking into consideration factors such as any updated CDC guidelines, new variants, any increases in COVID-19 cases in our service territories, and the overall level of risk to our employees and customers.

All of these safety measures have caused us to incur additional costs that, depending upon the duration of the COVID-19 pandemic, could have a material impact on our results of operations and liquidity.

We continue to provide our employees with educational information regarding the COVID-19 vaccine and are providing incentives and imposing surcharges on our medical plan to encourage employees to obtain the vaccine. Enforcement of these surcharges and precautionary measures may adversely impact our operations, including possible labor disruptions, employee attrition, and a reduced ability to replace departing employees.

## 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 LMP 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. 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, 2021, 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, we would need ICC approval to eliminate it.

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 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 their 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.

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. As of December 31, 2021, our regulatory assets were $3,367.1 million, and our regulatory liabilities were $3,960.3 million.

We expect to request or have requested recovery of the costs related to the following projects discussed in recent or pending rate proceedings, orders, and investigations involving our utilities:

- Prior to its acquisition by us, Integrys initiated an information technology project with the goal of improving the customer experience at its subsidiaries. Specifically, the project is expected to provide functional and technological benefits to the billing, call center, and credit collection functions. As of December 31, 2021, costs incurred for this project at PGL are still subject to approval by the ICC. WPS, NSG, MGU and MERC received approval to recover these costs in their most recent rate orders.

- 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 is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2021, PGL filed its 2020 reconciliation with the ICC, which, along with the 2019, 2018, 2017, and 2016 reconciliations, are still pending. As of December 31, 2021, there can be no assurance that all costs incurred under the QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

See Note 26, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

### *Climate and Equitable Jobs Act*

On September 15, 2021, the state of Illinois signed into law the Climate and Equitable Jobs Act. This new legislation includes, among other things, a path for Illinois to move towards 100% clean energy, expanded commitments to energy efficiency and renewable energy, additional consumer protections, and expanded ethics reform. The provisions in this legislation with the potential to have the most significant financial impact on PGL and NSG relate to the new consumer protection requirements. Effective January 1, 2023, natural gas utilities will no longer be allowed to charge late payment fees to low-income residential customers. In addition, effective September 15, 2021, the new legislation prohibits utilities from charging customers a fee when they elect to pay for service with a credit card. Instead, utilities will be required to seek recovery of costs incurred to process credit card payments through a rate proceeding or by establishing a recovery mechanism. On December 16, 2021, the ICC approved the use of a TPTFA rider for PGL. The TPTFA rider will allow PGL to recover the costs incurred for third-party transaction fees, effective December 27, 2021. See Note 26, Regulatory Environment, for more information on the rider. NSG recovers costs related to these third-party transaction fees through its recently established base rates.

We continue to evaluate the impact this legislation may have on our future results of operations.

### *Withhold Release Order Related to Silica-Based Products*

The CBP issued a WRO in June 2021, applicable to certain silica-based products originating from the Xinjiang Uyghur Autonomous Region of China, such as polysilicon, included in the manufacturing of solar panels. The WRO was issued over allegations of widespread, state-backed forced labor in the region. A significant percentage of the world's polysilicon supply comes from China, and as a result of the WRO, many solar panels imported into the United States are being held by the CBP on suspicion that they originated from, or contain components that originated from, this region in China. Solar panels will only be released after the importer provides satisfactory evidence to the contrary, which can be an arduous process. We have been notified that one of our solar panel suppliers has experienced delays associated with this WRO. We are evaluating options to mitigate these delays and maintain original project schedules, although we could experience project delays as a result of this WRO. The project delays could impact Badger Hollow II, which is currently under construction. Also, we cannot currently predict what, if any, impact this supply disruption will have on future solar projects included in our capital plan.

### *United States Department of Commerce Complaint*

In August 2021, a group of anonymous domestic solar manufacturers filed a petition (AD/CVD) with the DOC seeking to impose new tariffs on solar panels and cells imported from several countries, including Malaysia, Vietnam, and Thailand. The petitioners claim that Chinese solar manufacturers are shifting products to these countries to avoid the tariffs required on products imported from China. In September 2021, the DOC asked that the anonymous group amend its petition to provide more detail and asked the group to identify its members. In its response to the DOC, the anonymous group refused and argued that identifying its members could expose them to retribution from the Chinese solar industry, which dominates the global solar supply chain for critical solar panel components. In November 2021, the DOC rejected the petition filed by the anonymous group and cited the group's anonymity as a driving factor in the denial.

### *Infrastructure Investment and Jobs Act*

In November 2021, President Biden signed into law the Infrastructure Investment and Jobs Act, which provides for approximately $1.2 trillion of federal spending over the next five years, including approximately $85 billion for investments in power, utilities, and renewables infrastructure across the United States. We expect funding from this Act will support the work we are doing to reduce GHG emissions, increase EV charging, and strengthen and protect the energy grid. Funding in the Act should also help to expand emerging technologies, like hydrogen and carbon management, as we continue the transition to a clean energy future. We believe the Infrastructure Investment and Jobs Act will accelerate investment in projects that will help us meet our net zero emission goals to the benefit of our customers, the communities we serve, and our company.

### *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, this proposal, if adopted, would reduce our after-tax equity earnings from ATC by approximately $7 million annually. The transmission costs WE and WPS are required to pay ATC after the effective date would also be reduced by this proposal.

### *American Transmission Company Allowed Return on Equity Complaints*

On November 21, 2019, the FERC issued an order (November 2019 Order) related to the methodology used to calculate the base ROE for all MISO transmission owners, including ATC. Based on 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's modified methodology reduced the base ROE that ATC is allowed to collect on a going-forward basis, as discussed below. In response to the FERC's decision, requests for the FERC to rehear the November 2019 Order in its entirety were filed by various parties.

On May 21, 2020, the FERC issued an order (May 2020 Order) that granted in part and denied in part the requests to rehear the November 2019 Order. In the May 2020 Order, the FERC made additional revisions to its base ROE methodology, including adding the use of the risk premium model. As discussed below, the additional revisions made by the FERC increased ATC's base ROE authorized in the November 2019 Order on a going-forward basis. Various parties filed requests to rehear certain parts of the May 2020 Order with the FERC, but the FERC issued an order in response to the rehearing requests during November 2020 (November 2020 Order) that confirmed the ROE authorized in the May 2020 Order. Petitions for review of the November 2019 Order, relevant parts of the May 2020 Order, and the November 2020 Order have also been filed with the D.C. Circuit Court of Appeals.

**First Return on Equity Complaint**

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting to reduce the base ROE used by MISO transmission owners, including ATC, from 12.2% to 9.15%. In September 2016, the FERC issued an order requiring MISO transmission owners to collect a reduced base ROE of 10.32%. This order also allowed the continued collection of any previously authorized ROE incentive adders. For MISO transmission owners, a 0.5% incentive adder was approved by the FERC in January 2015. The FERC then issued the November 2019 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. The November 2019 Order further reduced the base ROE for all MISO transmission owners, including ATC, to 9.88%, effective as of September 28, 2016 and prospectively. The November 2019 Order also continued to allow the collection of previously authorized ROE incentive adders, but ATC's ROE incentive adder of 0.5% only applies to revenues collected after January 6, 2015. In response to the rehearing requests filed related to the November 2019 Order, the FERC issued another order in May 2020. This May 2020 Order increased the base ROE for all MISO transmission owners, including ATC, from the 9.88% authorized in the November 2019 Order to 10.02%, effective as of September 28, 2016 and prospectively. The May 2020 Order also allowed the continued collection of previously authorized ROE incentive adders. However, ATC's 0.5% ROE incentive adder may be eliminated going forward, as discussed above.

ATC is 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. As a result, ATC is expected to continue providing WE and WPS with net refunds related to the transmission costs they paid during the two refund periods through the end of February 2022. These refunds are being applied to WE's and WPS's PSCW-approved escrow accounting for transmission expense.

**Second Return on Equity Complaint**

In February 2015, a second complaint was filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners, including ATC, to 8.67%, with a refund effective date retroactive to February 12, 2015. The FERC also addressed this second complaint in the November 2019 Order. Similar to the first complaint, the November 2019 Order stated that the base ROE of 9.88% and the collection of previously authorized ROE incentive adders, such as ATC's 0.5% adder, were reasonable for the period covered by the second complaint, February 12, 2015 through May 10, 2016. However, in the November 2019 Order, the FERC relied on certain provisions of the Federal Power Act to dismiss the second complaint and to determine that refunds were not allowed for this period. In its May 2020 Order, the FERC stated the new base ROE of 10.02% and the collection of previously authorized ROE incentive adders were reasonable for the period covered by the second complaint. However, the FERC relied on the same provisions of the Federal Power Act to again dismiss the complaint and determine that refunds were not allowed for this period. The FERC also denied the requests to rehear both the dismissal of the second complaint and the determination that no refunds are allowed for the second complaint period.

Due to the various outstanding petitions related to the November 2019 Order, May 2020 Order, and November 2020 Order, refunds could still be required for the second complaint period. Therefore, our financials continue to reflect a liability of $39.1 million, reducing our equity earnings from ATC. This liability is based on a 10.52% ROE for the second complaint period. If it is ultimately determined that a refund is required for the second complaint period, we would not expect any such refund to have a material impact on our financial statements or results of operations in the future. In addition, WE and WPS would be entitled to receive a portion of the refund from ATC for the benefit of their customers.

## *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, land quality, and climate change.

## 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 risks, described in further detail below, include but are not limited to:

### *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 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.

Due to the cold temperatures, wind, snow and ice throughout the central part of the country during February 2021, the cost of gas purchased for our natural gas utility customers was temporarily driven higher than our normal winter weather expectations. As a result of this extreme weather event, we requested approval for the recovery of an additional $322 million of natural gas costs across our service territories, above what was either set as a benchmark in our respective GCRMs or included in rates. See Note 26, Regulatory Environment, for more information on our recovery efforts associated with these costs.

### *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 during 2021 and 2020, as measured by degree days, can be found in Results of Operations.

### *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, 2021 and 2020, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $24.0 million and $20.3 million in 2021 and 2020, 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. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

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

| *(in millions)* | As of December 31, 2021 | Expected Return on Assets in 2022 |
|---|---|---|
| Pension trust funds | $ **3,328.9** | 6.88 % |
| OPEB trust funds | $ **1,000.2** | 7.00 % |

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.

### *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 necessary 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 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 and inflation.

For additional information concerning 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 judgements 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 rate-making principles followed by the various 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. As of December 31, 2021, we had $3,367.1 million in regulatory assets and $3,960.3 million in regulatory liabilities. See Note 6, Regulatory Assets and Liabilities, for more information.

### *Goodwill*

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2021. 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. Since all of our reporting units 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 an equal weighting of the guideline public company method and the guideline merged and acquired company method. 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, 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.

Performing an impairment evaluation involves a significant degree of estimation and judgement 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, and Note 26, Regulatory Environment, for more information on our retired generating units, including various approvals we received from the FERC and the PSCW.

### *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. We believe that such changes in costs would be recovered or refunded at our utilities through the rate-making 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. Each factor below reflects an evaluation of the change based on a change in that assumption only.

| **Actuarial Assumption**<br>***(in millions, except percentages)*** | **Percentage-Point Change in Assumption** | **Impact on Projected Benefit Obligation** | **Impact on 2021 Pension Cost** |
|---|---|---|---|
| Discount rate | (0.5) | $ 203.0 | $ 23.6 |
| Discount rate | 0.5 | (176.3) | (20.7) |
| Rate of return on plan assets | (0.5) | N/A | 14.5 |
| Rate of return on plan assets | 0.5 | N/A | (14.5) |

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. 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 2021 Postretirement Benefit Cost** |
|---|---|---|---|
| Discount rate | (0.5) | $ 32.3 | $ 3.5 |
| Discount rate | 0.5 | (28.3) | (3.1) |
| Health care cost trend rate | (0.5) | (17.2) | (3.5) |
| Health care cost trend rate | 0.5 | 19.6 | 4.0 |
| Rate of return on plan assets | (0.5) | N/A | 4.7 |
| Rate of return on plan assets | 0.5 | N/A | (4.7) |

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 6.88%, 6.87%, and 7.12% in 2021, 2020, and 2019, respectively. The actual rate of return on pension plan assets, net of fees, was 9.5%, 12.65%, and 18.89%, in 2021, 2020, and 2019, 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 $531.7 million and $499.5 million as of December 31, 2021 and 2020, 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 2022 annual effective tax rate to be between 18.5% and 19.5%. 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, 2021 and 2020, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 24, 2022, 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 distribution 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. 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 by 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. Future decisions of the Commissions will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates, and any refunds that may be required.

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. The Company had $3,367.1 million and $3,960.3 million of regulatory assets and liabilities, respectively, as of December 31, 2021.

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 impacted account balances and disclosures and the subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Given that management's accounting judgments can be based on assumptions about the outcome of future decisions by the Commissions, 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 uncertainty of future decisions by the Commissions 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 identification of costs recorded as regulatory assets and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates.

- We inquired of Company management and independently obtained and read: (1) relevant regulatory orders issued by the Commissions for the Company and other public utilities in each respective state, (2) company filings, (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 inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, for any evidence that might contradict management's assertions.

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

- 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 24, 2022

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, 2021, 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, 2021, 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, 2021, of the Company and our report dated February 24, 2022, 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 audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits 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 audits provide 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 24, 2022

## B. CONSOLIDATED INCOME STATEMENTS

| Year Ended December 31<br>*(in millions, except per share amounts)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **Operating revenues** | **$ 8,316.0** | $ 7,241.7 | $ 7,523.1 |
| | | | |
| **Operating expenses** | | | |
| Cost of sales | **3,311.0** | 2,319.5 | 2,678.8 |
| Other operation and maintenance | **2,005.5** | 2,032.2 | 2,184.8 |
| Depreciation and amortization | **1,074.3** | 975.9 | 926.3 |
| Property and revenue taxes | **210.3** | 208.0 | 201.8 |
| **Total operating expenses** | **6,601.1** | 5,535.6 | 5,991.7 |
| | | | |
| **Operating income** | **1,714.9** | 1,706.1 | 1,531.4 |
| | | | |
| Equity in earnings of transmission affiliates | **158.1** | 175.8 | 127.6 |
| Other income, net | **133.2** | 79.5 | 102.2 |
| Interest expense | **471.1** | 493.7 | 501.5 |
| Loss on debt extinguishment | **36.3** | 38.4 | — |
| **Other expense** | **(216.1)** | (276.8) | (271.7) |
| | | | |
| Income before income taxes | **1,498.8** | 1,429.3 | 1,259.7 |
| Income tax expense | **200.3** | 227.9 | 125.0 |
| **Net income** | **1,298.5** | 1,201.4 | 1,134.7 |
| | | | |
| Preferred stock dividends of subsidiary | **1.2** | 1.2 | 1.2 |
| Net (income) loss attributed to noncontrolling interests | **3.0** | (0.3) | 0.5 |
| **Net income attributed to common shareholders** | **$ 1,300.3** | $ 1,199.9 | $ 1,134.0 |
| | | | |
| **Earnings per share** | | | |
| Basic | **$ 4.12** | $ 3.80 | $ 3.60 |
| Diluted | **$ 4.11** | $ 3.79 | $ 3.58 |
| | | | |
| **Weighted average common shares outstanding** | | | |
| Basic | **315.4** | 315.4 | 315.4 |
| Diluted | **316.3** | 316.5 | 316.7 |

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<br>*(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **Net income** | **$ 1,298.5** | $ 1,201.4 | $ 1,134.7 |
| | | | |
| **Other comprehensive income (loss), net of tax** | | | |
| **Derivatives accounted for as cash flow hedges** | | | |
| Net derivative gain (loss), net of tax expense (benefit) of $0.2, $(1.6), and $(1.3), respectively | **0.6** | (4.3) | (3.5) |
| Reclassification of realized net derivative (gain) loss to net income, net of tax | **0.9** | 1.5 | (0.8) |
| **Cash flow hedges, net** | **1.5** | (2.8) | (4.3) |
| | | | |
| **Defined benefit plans** | | | |
| Pension and OPEB adjustments arising during the period, net of tax expense (benefit) of $0.7, $(0.2), and $1.0, respectively | **1.7** | (0.5) | 2.6 |
| Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax | **0.4** | 0.6 | 0.2 |
| **Defined benefit plans, net** | **2.1** | 0.1 | 2.8 |
| | | | |
| **Other comprehensive income (loss), net of tax** | **3.6** | (2.7) | (1.5) |
| | | | |
| **Comprehensive income** | **1,302.1** | 1,198.7 | 1,133.2 |
| | | | |
| Preferred stock dividends of subsidiary | **1.2** | 1.2 | 1.2 |
| Comprehensive (income) loss attributed to noncontrolling interests | **3.0** | (0.3) | 0.5 |
| **Comprehensive income attributed to common shareholders** | **$ 1,303.9** | $ 1,197.2 | $ 1,132.5 |

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

## D. CONSOLIDATED BALANCE SHEETS

| At December 31<br>*(in millions, except share and per share amounts)* | 2021 | 2020 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 16.3** | $ 24.8 |
| Accounts receivable and unbilled revenues, net of reserves of $198.3 and $220.1, respectively | **1,505.7** | 1,202.8 |
| Materials, supplies, and inventories | **635.8** | 528.6 |
| Prepayments | **245.5** | 263.4 |
| Other | **253.4** | 63.4 |
| **Current assets** | **2,656.7** | 2,083.0 |
| | | |
| **Long-term assets** | | |
| Property, plant, and equipment, net of accumulated depreciation and amortization of $9,889.3 and $9,364.7, respectively | **26,982.4** | 25,707.4 |
| Regulatory assets (December 31, 2021 includes $100.7 related to WEPCo Environmental Trust) | **3,264.8** | 3,524.1 |
| Equity investment in transmission affiliates | **1,789.4** | 1,764.3 |
| Goodwill | **3,052.8** | 3,052.8 |
| Pension and OPEB assets | **881.3** | 600.9 |
| Other | **361.1** | 295.6 |
| **Long-term assets** | **36,331.8** | 34,945.1 |
| **Total assets** | **$ 38,988.5** | $ 37,028.1 |
| | | |
| **Liabilities and Equity** | | |
| **Current liabilities** | | |
| Short-term debt | **$ 1,897.0** | $ 1,776.9 |
| Current portion of long-term debt (December 31, 2021 includes $8.8 related to WEPCo Environmental Trust) | **169.4** | 785.8 |
| Accounts payable | **1,005.7** | 880.7 |
| Other | **680.9** | 704.7 |
| **Current liabilities** | **3,753.0** | 4,148.1 |
| | | |
| **Long-term liabilities** | | |
| Long-term debt (December 31, 2021 includes $102.7 related to WEPCo Environmental Trust) | **13,523.7** | 11,728.1 |
| Deferred income taxes | **4,308.5** | 4,059.8 |
| Deferred revenue, net | **389.2** | 412.2 |
| Regulatory liabilities | **3,946.0** | 3,928.1 |
| Environmental remediation liabilities | **532.6** | 532.9 |
| Pension and OPEB obligations | **219.0** | 327.0 |
| Other | **1,203.2** | 1,229.4 |
| **Long-term liabilities** | **24,122.2** | 22,217.5 |
| | | |
| Commitments and contingencies (Note 24) | | |
| | | |
| **Common shareholders' equity** | | |
| Common stock – $0.01 par value; 325,000,000 shares authorized; 315,434,531 shares outstanding | **3.2** | 3.2 |
| Additional paid in capital | **4,138.1** | 4,143.7 |
| Retained earnings | **6,775.1** | 6,329.6 |
| Accumulated other comprehensive loss | **(3.2)** | (6.8) |
| **Common shareholders' equity** | **10,913.2** | 10,469.7 |
| | | |
| Preferred stock of subsidiary | **30.4** | 30.4 |
| Noncontrolling interests | **169.7** | 162.4 |
| **Total liabilities and equity** | **$ 38,988.5** | $ 37,028.1 |

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<br>*(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **Operating activities** | | | |
| Net income | **$ 1,298.5** | $ 1,201.4 | $ 1,134.7 |
| Reconciliation to cash provided by operating activities | | | |
| Depreciation and amortization | **1,074.3** | 975.9 | 926.3 |
| Deferred income taxes and ITCs, net | **151.1** | 209.4 | 162.9 |
| Contributions and payments related to pension and OPEB plans | **(66.3)** | (113.2) | (65.9) |
| Equity income in transmission affiliates, net of distributions | **(25.1)** | (29.1) | (2.9) |
| Change in – | | | |
| Accounts receivable and unbilled revenues, net | **(249.2)** | 16.1 | 98.2 |
| Materials, supplies, and inventories | **(107.2)** | 21.2 | (1.5) |
| Amounts recoverable from customers | **(82.3)** | 0.9 | 29.8 |
| Other current assets | **22.2** | 12.5 | (36.9) |
| Accounts payable | **126.9** | (61.3) | 1.5 |
| Other current liabilities | **(17.2)** | (41.2) | 78.7 |
| Other, net | **(93.0)** | 3.4 | 20.6 |
| **Net cash provided by operating activities** | **2,032.7** | 2,196.0 | 2,345.5 |
| | | | |
| **Investing activities** | | | |
| Capital expenditures | **(2,252.8)** | (2,238.8) | (2,260.8) |
| Acquisition of Jayhawk | **(119.9)** | — | — |
| Acquisition of Blooming Grove, net of restricted cash acquired of $24.1 | **—** | (364.6) | — |
| Acquisition of Tatanka Ridge | **—** | (239.9) | — |
| Acquisition of Upstream, net of cash and restricted cash acquired of $9.2 | **—** | — | (268.2) |
| Capital contributions to transmission affiliates | **—** | (21.2) | (52.6) |
| Proceeds from the sale of assets and businesses | **21.9** | 20.3 | 37.6 |
| Proceeds from the sale of investments held in rabbi trust | **18.7** | 56.2 | 0.2 |
| Purchase of investments held in rabbi trust | **—** | (37.8) | — |
| Reimbursement for ATC's construction costs | **—** | 1.1 | 32.4 |
| Insurance proceeds received for property damage | **—** | 23.2 | — |
| Other, net | **20.3** | (5.3) | 16.5 |
| **Net cash used in investing activities** | **(2,311.8)** | (2,806.8) | (2,494.9) |
| | | | |
| **Financing activities** | | | |
| Exercise of stock options | **15.7** | 43.8 | 67.0 |
| Purchase of common stock | **(33.1)** | (99.2) | (140.1) |
| Dividends paid on common stock | **(854.8)** | (798.0) | (744.5) |
| Issuance of long-term debt | **2,383.8** | 2,373.6 | 1,895.0 |
| Retirement of long-term debt | **(1,260.4)** | (1,767.0) | (360.1) |
| Issuance of short-term loan | **0.9** | 340.0 | — |
| Repayment of short-term loan | **(340.0)** | — | — |
| Change in other short-term debt | **459.2** | 606.1 | (609.3) |
| Payments for debt extinguishment and issuance costs | **(67.2)** | (55.8) | (12.5) |
| Purchase of additional ownership interest in Upstream from noncontrolling interest | **—** | (31.0) | — |
| Other, net | **(10.1)** | (11.4) | (9.9) |
| **Net cash provided by financing activities** | **294.0** | 601.1 | 85.6 |
| | | | |
| **Net change in cash, cash equivalents, and restricted cash** | **14.9** | (9.7) | (63.8) |
| Cash, cash equivalents, and restricted cash at beginning of year | **72.6** | 82.3 | 146.1 |
| **Cash, cash equivalents, and restricted cash at end of year** | **$ 87.5** | $ 72.6 | $ 82.3 |

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 Income (Loss) | Total Common Shareholders' Equity | Preferred Stock of Subsidiary | Non-controlling Interests | Total Equity |
| **Balance at December 31, 2018** | $ 3.2 | $ 4,250.1 | $ 5,538.2 | $ (2.6) | $ 9,788.9 | $ 30.4 | $ 23.4 | $ 9,842.7 |
| Net income attributed to common shareholders | — | — | 1,134.0 | — | 1,134.0 | — | — | 1,134.0 |
| Net loss attributed to noncontrolling interests | — | — | — | — | — | — | (0.5) | (0.5) |
| Other comprehensive loss | — | — | — | (1.5) | (1.5) | — | — | (1.5) |
| Common stock dividends of $2.36 per share | — | — | (744.5) | — | (744.5) | — | — | (744.5) |
| Exercise of stock options | — | 67.0 | — | — | 67.0 | — | — | 67.0 |
| Purchase of common stock | — | (140.1) | — | — | (140.1) | — | — | (140.1) |
| Acquisition of a noncontrolling interest | — | — | — | — | — | — | 69.0 | 69.0 |
| Capital contributions from noncontrolling interest | — | — | — | — | — | — | 21.0 | 21.0 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | (2.1) | (2.1) |
| Stock-based compensation and other | — | 9.6 | — | — | 9.6 | — | — | 9.6 |
| **Balance at December 31, 2019** | $ 3.2 | $ 4,186.6 | $ 5,927.7 | $ (4.1) | $ 10,113.4 | $ 30.4 | $ 110.8 | $ 10,254.6 |
| Net income attributed to common shareholders | — | — | 1,199.9 | — | 1,199.9 | — | — | 1,199.9 |
| Net income attributed to noncontrolling interests | — | — | — | — | — | — | 0.3 | 0.3 |
| Other comprehensive loss | — | — | — | (2.7) | (2.7) | — | — | (2.7) |
| Common stock dividends of $2.53 per share | — | — | (798.0) | — | (798.0) | — | — | (798.0) |
| Exercise of stock options | — | 43.8 | — | — | 43.8 | — | — | 43.8 |
| Purchase of common stock | — | (99.2) | — | — | (99.2) | — | — | (99.2) |
| Purchase of additional ownership interest in Upstream from noncontrolling interest | — | — | — | — | — | — | (31.0) | (31.0) |
| Acquisition of noncontrolling interests | — | — | — | — | — | — | 85.0 | 85.0 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | (2.7) | (2.7) |
| Stock-based compensation and other | — | 12.5 | — | — | 12.5 | — | — | 12.5 |
| **Balance at December 31, 2020** | $ 3.2 | $ 4,143.7 | $ 6,329.6 | $ (6.8) | $ 10,469.7 | $ 30.4 | $ 162.4 | $ 10,662.5 |
| Net income attributed to common shareholders | **—** | **—** | **1,300.3** | **—** | **1,300.3** | **—** | **—** | **1,300.3** |
| Net loss attributed to noncontrolling interests | **—** | **—** | **—** | **—** | **—** | **—** | **(3.0)** | **(3.0)** |
| Other comprehensive income | **—** | **—** | **—** | **3.6** | **3.6** | **—** | **—** | **3.6** |
| Common stock dividends of $2.71 per share | **—** | **—** | **(854.8)** | **—** | **(854.8)** | **—** | **—** | **(854.8)** |
| Exercise of stock options | **—** | **15.7** | **—** | **—** | **15.7** | **—** | **—** | **15.7** |
| Purchase of common stock | **—** | **(33.1)** | **—** | **—** | **(33.1)** | **—** | **—** | **(33.1)** |
| Acquisition of noncontrolling interest | **—** | **—** | **—** | **—** | **—** | **—** | **6.3** | **6.3** |
| Capital contributions from noncontrolling interest | **—** | **—** | **—** | **—** | **—** | **—** | **7.6** | **7.6** |
| Distributions to noncontrolling interests | **—** | **—** | **—** | **—** | **—** | **—** | **(4.1)** | **(4.1)** |
| Stock-based compensation and other | **—** | **11.8** | **—** | **—** | **11.8** | **—** | **0.5** | **12.3** |
| **Balance at December 31, 2021** | **$ 3.2** | **$ 4,138.1** | **$ 6,775.1** | **$ (3.2)** | **$ 10,913.2** | **$ 30.4** | **$ 169.7** | **$ 11,113.3** |

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 1.6 million electric customers and 3.0 million natural gas customers, and owns approximately 60% of ATC.

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, 2021 related to the minority interests at Bishop Hill III, Coyote Ridge, Upstream, Blooming Grove, Tatanka Ridge, and Jayhawk held by third parties.

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 ownership interests in several wind generating facilities, is also included in this segment. See Note 2, Acquisitions, for more information on the WECI wind 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, WBS, and also included the operations of PDL prior to the sale of its remaining solar facilities in the fourth quarter of 2020. See Note 3, Dispositions, for more information on the sale of these solar facilities.

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. See Note 26, Regulatory Environment, for more information on how COVID-19 has affected the cost recovery mechanisms for our utility companies.

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. However, as a result of the extreme weather in the Midwest in February 2021, the cost of gas purchased for our natural gas customers was temporarily driven significantly higher than our normal winter weather expectations. See Note 26, Regulatory Environment, for more information on the recovery of these high natural gas costs.

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, PGL's rates include a rider for income tax expense changes resulting from the Tax Legislation and a cost recovery mechanism for SMP costs and, and similarly, MERC's rates include riders to recover costs incurred to replace or modify natural gas facilities. See Note 26, Regulatory Environment, for more information on how COVID-19 has affected the cost recovery mechanisms for our company.

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 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. 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 generation revenues from WECI's ownership interests in wind generation facilities continued to grow with new acquisitions in 2021. See Note 2, Acquisitions, for more information on recent acquisitions. Most of these wind 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 wind 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 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 wind 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 2021, 2020, and 2019, we recorded $23.3 million, $22.9 million, and $25.4 million, respectively, of revenues related to these deferred carrying costs.

### *Other Operating Revenues*

**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. See Note 26, Regulatory Environment, for more information.
- PGL and NSG were authorized to implement a SPC rider for the recovery of incremental direct costs resulting from the COVID-19 pandemic, foregone late fees and reconnection charges, and the costs associated with their bill payment assistance programs. See Note 26, Regulatory Environment, for more information.
- 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.

Effective January 1, 2020, we adopted FASB ASU 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, using the modified retrospective transition method. This ASU amends the impairment model to utilize an expected loss methodology in place of the incurred loss methodology for financial instruments, including trade receivables. The amendment requires entities to consider a broader range of information to estimate expected credit losses, which may result in earlier recognition of loss. The cumulative effect of adopting this standard was not significant to our financial statements.

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 wind generating facilities through agreements with several large high credit quality counterparties. At the corporate and other segment, we had an accounts receivable and unbilled revenue balance at the beginning of 2020 related to the PDL residential solar facilities, which were sold in November 2020. See Note 3, Dispositions, for more information.

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 to mitigate credit risk. See Note 26, Regulatory Environment, for information on certain regulatory actions that were and/or are being taken for the purpose of ensuring that essential utility services are available to our customers during the COVID-19 pandemic.

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

| *(in millions)* | 2021 | 2020 |
|---|---|---|
| Natural gas in storage | **$ 326.0** | $ 224.9 |
| Materials and supplies | **225.3** | 218.1 |
| Fossil fuel | **84.5** | 85.6 |
| **Total** | **$ 635.8** | $ 528.6 |

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 19% and 22% of total inventories at December 31, 2021 and 2020, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2021 and 2020, exceeded the LIFO cost by $114.2 million and $31.5 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.67 at December 31, 2021, and $2.31 at December 31, 2020.

Substantially all other natural gas in storage, materials and supplies, 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 rate-making process in a period different from the period they would have been recognized by a nonregulated company. When this occurs, regulatory assets and regulatory 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 | 2021 | 2020 | 2019 |
|---|---|---|---|
| WE | **3.09%** | 3.19% | 3.11% |
| WPS | **2.66%** | 2.63% | 2.44% |
| WG | **2.44%** | 2.33% | 2.29% |
| PGL | **3.12%** | 3.16% | 3.20% |
| NSG | **2.52%** | 2.48% | 2.48% |
| MERC | **2.58%** | 2.47% | 2.33% |
| MGU | **2.70%** | 2.67% | 2.54% |
| UMERC | **2.94%** | 2.97% | 2.87% |

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 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, WBS, WG, and UMERC. Approximately 50% of WE's, WPS's, WG's, UMERC's, and WBS's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. The AFUDC calculation for WBS uses the WPS AFUDC retail rate, while our utilities' AFUDC rates are determined by their respective state commissions, each with specific requirements. Average AFUDC rates are shown below:

| | 2021 | |
|---|---|---|
| | **Average AFUDC Retail Rate** | **Average AFUDC Wholesale Rate** |
| WE | **8.68%** | **1.79%** |
| WPS | **7.55%** | **1.04%** |
| WG | **8.32%** | **N/A** |
| UMERC | **6.28%** | **N/A** |
| WBS | **7.55%** | **N/A** |

Our regulated utilities and WBS recorded the following AFUDC for the years ended December 31:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **AFUDC – Debt** | | | |
| WE | **$ 2.9** | $ 2.6 | $ 1.5 |
| WPS | **3.5** | 4.6 | 2.4 |
| WG | **0.2** | 0.6 | 0.5 |
| UMERC | **0.1** | — | 1.3 |
| WBS | **0.1** | 0.1 | 0.1 |
| Other | **—** | 0.1 | 0.1 |
| **Total AFUDC – Debt** | **$ 6.8** | $ 8.0 | $ 5.9 |
| | | | |
| **AFUDC – Equity** | | | |
| WE | **$ 7.9** | $ 7.0 | $ 3.7 |
| WPS | **9.0** | 11.8 | 5.7 |
| WG | **0.6** | 1.6 | 1.3 |
| UMERC | **0.1** | 0.1 | 3.3 |
| WBS | **0.2** | 0.2 | 0.2 |
| Other | **0.2** | 0.2 | 0.2 |
| **Total AFUDC – Equity** | **$ 18.0** | $ 20.9 | $ 14.4 |

**(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, developing a centralized repository for data to improve analytics and reporting, targeted enterprise resource planning systems, a project management tool, and a power generation employee scheduling system. 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, 2021 and 2020, we had $3.3 million and $1.8 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. Amortization and accumulated amortization for the years ended December 31, 2021 and 2020 were 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 at all of our reporting units that carry 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 for the excess of the carrying amount of the goodwill over its implied fair value. 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 the fair value of the asset. 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 in comparison to the fair value of the asset.

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, 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.

**(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) Intangible Liabilities**—Our finite-lived intangible liabilities include revenue contracts, consisting of PPAs and a proxy revenue swap, in addition to interconnection agreements, which were all obtained through the acquisitions of wind generation facilities by WECI in our non-utility energy infrastructure segment. Intangible liabilities are amortized on a straight-line basis over their estimated useful life. Amortization of revenue contracts is recorded within operating revenues in the income statements. Amortization related to the interconnection agreements 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 intangible liabilities assumed impact the amount and timing of future amortization.

**(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 are subject to awards outstanding as of May 6, 2021, 9.0 million shares are 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, rather than estimating potential future forfeitures and recording them over the vesting period.

### *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:

| | 2021 | 2020 | 2019 |
|---|---|---|---|
| Stock options granted | **530,612** | 554,594 | 476,418 |
| | | | |
| Estimated weighted-average fair value per stock option | **$ 13.20** | $ 10.94 | $ 8.60 |
| | | | |
| **Assumptions used to value the options:** | | | |
| Risk-free interest rate | **0.1% – 0.9%** | 0.2% – 1.9% | 2.5% – 2.7% |
| Dividend yield | **2.9 %** | 3.0 % | 3.6 % |
| Expected volatility | **21.0 %** | 16.3 % | 17.0 % |
| Expected life (years) | **8.7** | 8.6 | 8.5 |

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 certain officers and all 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. Under the plan, the ultimate number of units that will be awarded is dependent on our total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over three years, as well as other performance metrics as may be determined by the Compensation Committee. Under the terms of the award, participants may earn between 0% and 175% of the performance unit award based on our total shareholder return. Pursuant to the terms of the plan, these percentages can be adjusted upwards or downwards by up to 10% based on our performance against additional performance measures, if any, adopted by the Compensation Committee. Performance units also accrue forfeitable dividend equivalents in the form of additional performance units.

All grants of performance units are settled in cash and are accounted for as liability awards accordingly. 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.

See Note 11, Common Equity, for more information on our stock-based compensation plans.

**(o) Earnings Per Share**—We compute basic earnings per share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. The calculation of diluted earnings per share for the years ended December 31, 2021 and 2020 excluded 769,030 and 207,445 stock options, respectively, that had an anti-dilutive effect. There were no securities that had an anti-dilutive effect for the year ended December 31, 2019.

**(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.

***Significant Judgments and Other Information***

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 wind 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**—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 associated with regulated operations 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. See Note 16, Income Taxes, for more information.

We recognize interest and penalties accrued, related to unrecognized tax benefits, in income tax expense in our income statements.

**(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 derivative 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 are categorized in Level 3 due to the significance of unobservable or internally-developed inputs.

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 coal combustion residual landfills and manufactured gas plant sites. See Note 9, Asset Retirement Obligations, for more information regarding coal combustion residual 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 coal combustion residual 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. 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. As a result, we did not have any significant concentrations of credit risk at December 31, 2021. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2021.

## 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 (or disposals) of assets or businesses, and transaction costs are capitalized in asset acquisitions. The purchase price of certain acquisitions described below includes intangibles recorded as long-term liabilities related to PPAs, an interconnection agreement, and a proxy revenue swap. See Note 10, Goodwill and Intangibles, for more information.

### Acquisition of Electric Generation Facility in Wisconsin

In November 2021, WE and WPS signed an asset purchase agreement to acquire Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electrical generation facility in Whitewater, Wisconsin, for $72.7 million. The transaction is expected to close in January 2023. In December 2021, WE and WPS filed an application with the PSCW for approval to acquire Whitewater. See Note 15, Leases, for more information.

### Acquisition of Wind Generation Facilities in Illinois

In June 2021, WECI signed an agreement to acquire a 90% ownership interest in Sapphire Sky, a 250 MW wind generating facility under construction in McLean County, Illinois, for approximately $412 million. The project has an offtake agreement with an unaffiliated third party for all of the energy to be produced by the facility for a period of 12 years. WECI's investment in Sapphire Sky is expected to qualify for PTCs. The transaction is subject to FERC approval and commercial operation is expected to begin by the end of 2022, at which time the transaction is expected to close. Sapphire Sky will be included in the non-utility energy infrastructure segment.

In December 2020, WECI completed the acquisition of a 90% ownership interest in Blooming Grove, a commercially operational 250 MW wind generating facility in McLean County, Illinois, for a total investment of $364.6 million, which includes transaction costs and is net of restricted cash acquired of $24.1 million. Blooming Grove has offtake agreements for all the energy produced with affiliates of two investment grade multinational companies for 12 years. WECI's investment in Blooming Grove qualifies for PTCs. Blooming Grove 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 | $ 488.3 |
| Accounts receivable | 0.3 |
| Other long-term assets | 2.9 |
| Accounts payable | (13.7) |
| Other current liabilities | (1.5) |
| Long-term liabilities | (68.7) |
| Noncontrolling interest | (43.0) |
| **Total purchase price** | $ 364.6 |

## Acquisition of a Wind Generation Facility in Kansas

In February 2021, WECI completed the acquisition of a 90% ownership interest in Jayhawk, a 190 MW wind generating facility in Bourbon and Crawford counties, Kansas, for $119.9 million, which included transaction costs. This project became commercially operational in December 2021. Subsequent to the acquisition, WECI incurred an additional $147.4 million of capital expenditures for the project for a total investment of $267.3 million. The project has an offtake agreement with an unaffiliated third party for all of the energy to be produced by the facility for a period of 10 years. WECI's investment in Jayhawk qualifies for PTCs. WECI is entitled to 99% of the tax benefits related to this facility for the first 10 years of commercial operation, after which we will be entitled to tax benefits equal to our ownership interest. Jayhawk 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 | $ 145.3 |
| Long-term liabilities | (11.8) |
| Long-term debt | (7.3) |
| Noncontrolling interest | (6.3) |
| **Total purchase price** | $ 119.9 |

## Acquisition of a Wind Generation Facility in South Dakota

In December 2020, WECI completed the acquisition of an 85% ownership interest in Tatanka Ridge, a 155 MW wind generating facility in Deuel County, South Dakota, that became commercially operational in January 2021. WECI's total investment was $239.9 million, which included transaction costs. Tatanka Ridge has offtake agreements for all the energy produced with an affiliate of an investment grade multinational company for 12 years and a well-established electric cooperative that serves utilities in multiple states for 10 years. WECI's investment in Tatanka Ridge qualifies for PTCs. WECI is entitled to 99% of the tax benefits related to this facility for the first 11 years of commercial operation, after which we will be entitled to tax benefits equal to our ownership interest. Tatanka Ridge 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)* | |
|---|---|
| Current assets | $ 37.3 |
| Net property, plant, and equipment | 301.2 |
| Current liabilities | (37.3) |
| Long-term liabilities | (19.3) |
| Noncontrolling interest | (42.0) |
| **Total purchase price** | $ 239.9 |

## Acquisition of Wind Generation Facilities in Nebraska

In August 2019, WECI signed an agreement to acquire an 80% ownership interest in Thunderhead, a 300 MW wind generating facility under construction in Antelope and Wheeler counties in Nebraska, for a total investment of approximately $338 million. In February 2020, WECI agreed to acquire an additional 10% ownership interest in Thunderhead for $43 million. The project has an offtake agreement for all of the energy to be produced by the facility for 12 years. WECI's investment in Thunderhead is expected to qualify for PTCs. The transaction was approved by FERC in April 2020, and commercial operation was initially expected to begin by the end of 2020. However, due to a delay in construction of the required substation, Thunderhead is now expected to begin commercial operation during the first half of 2022. The transaction is expected to close upon commercial operation. Thunderhead will be included in the non-utility energy infrastructure segment.

In January 2019, WECI completed the acquisition of an 80% ownership interest in Upstream, a commercially operational 202.5 MW wind generating facility, for $268.2 million, which included transaction costs and is net of cash and restricted cash acquired of $9.2 million. In February 2020, WECI signed an agreement to acquire an additional 10% ownership interest in Upstream for $31.0 million. Upstream is located in Antelope County, Nebraska and supplies energy to the Southwest Power Pool. Upstream's revenue will be substantially fixed over 10 years through an agreement with an unaffiliated third party. WECI's investment in Upstream qualifies for PTCs. Upstream 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 of the initial 80% ownership interest in Upstream.

| ***(in millions)*** | |
|---|---|
| Current assets | $ 0.4 |
| Net property, plant, and equipment | 341.6 |
| Other long-term assets | 14.8 |
| Current liabilities | (4.6) |
| Long-term liabilities | (15.0) |
| Noncontrolling interest | (69.0) |
| **Total purchase price** | $ 268.2 |

## NOTE 3—DISPOSITIONS

## Corporate and Other Segment

### *Sale of Certain WPS Power Development, LLC Solar Power Generation Facilities*

In November 2020, we sold a portfolio of residential solar facilities owned by PDL for $10.5 million. These solar facilities were located in California and Hawaii. During the fourth quarter of 2020, we recorded an after-tax gain on the sale of $3.0 million primarily related to the recognition of deferred ITCs, which were included as a reduction of income tax expense on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations of these facilities remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

In 2019, we sold four solar power generation facilities owned by PDL for $26.3 million. These solar facilities were located in Massachusetts. In 2019, we recorded an after-tax gain on the sales of $6.5 million primarily related to the recognition of deferred ITCs, which were included as a reduction of income tax expense on our income statements. The assets included in the sales were not material and, therefore, were not presented as held for sale. The results of operations of these facilities remained in continuing operations through the sale dates as the sales did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

## 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 have 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, 2021** | | | | | | | | |
| Electric | **$ 4,516.6** | **$ —** | **$ —** | **$ 4,516.6** | **$ —** | **$ —** | **$ —** | **$ 4,516.6** |
| Natural gas | **1,490.3** | **1,630.3** | **494.0** | **3,614.6** | **46.8** | **—** | **(43.8)** | **3,617.6** |
| **Total regulated revenues** | **6,006.9** | **1,630.3** | **494.0** | **8,131.2** | **46.8** | **—** | **(43.8)** | **8,134.2** |
| Other non-utility revenues | **—** | **—** | **17.8** | **17.8** | **92.8** | **—** | **(9.1)** | **101.5** |
| **Total revenues from contracts with customers** | **6,006.9** | **1,630.3** | **511.8** | **8,149.0** | **139.6** | **—** | **(52.9)** | **8,235.7** |
| Other operating revenues | **30.1** | **42.5** | **7.2** | **79.8** | **399.9** | **0.5** | **(399.9)** (1) | **80.3** |
| **Total operating revenues** | **$ 6,037.0** | **$ 1,672.8** | **$ 519.0** | **$ 8,228.8** | **$ 539.5** | **$ 0.5** | **$ (452.8)** | **$ 8,316.0** |

| *(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, 2020** | | | | | | | | |
| Electric | $ 4,266.1 | $ — | $ — | $ 4,266.1 | $ — | $ — | $ — | $ 4,266.1 |
| Natural gas | 1,195.6 | 1,267.9 | 361.0 | 2,824.5 | 44.4 | — | (42.0) | 2,826.9 |
| **Total regulated revenues** | 5,461.7 | 1,267.9 | 361.0 | 7,090.6 | 44.4 | — | (42.0) | 7,093.0 |
| Other non-utility revenues | — | — | 17.1 | 17.1 | 66.6 | 1.7 | (9.1) | 76.3 |
| **Total revenues from contracts with customers** | 5,461.7 | 1,267.9 | 378.1 | 7,107.7 | 111.0 | 1.7 | (51.1) | 7,169.3 |
| Other operating revenues | 11.8 | 54.0 | 6.0 | 71.8 | 397.5 | 0.5 | (397.4) (1) | 72.4 |
| **Total operating revenues** | $ 5,473.5 | $ 1,321.9 | $ 384.1 | $ 7,179.5 | $ 508.5 | $ 2.2 | $ (448.5) | $ 7,241.7 |

| *(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, 2019** | | | | | | | | |
| Electric | $ 4,307.7 | $ — | $ — | $ 4,307.7 | $ — | $ — | $ — | $ 4,307.7 |
| Natural gas | 1,324.1 | 1,332.4 | 411.6 | 3,068.1 | 47.4 | — | (44.1) | 3,071.4 |
| **Total regulated revenues** | 5,631.8 | 1,332.4 | 411.6 | 7,375.8 | 47.4 | — | (44.1) | 7,379.1 |
| Other non-utility revenues | — | 0.1 | 16.6 | 16.7 | 55.2 | 4.0 | (5.7) | 70.2 |
| **Total revenues from contracts with customers** | 5,631.8 | 1,332.5 | 428.2 | 7,392.5 | 102.6 | 4.0 | (49.8) | 7,449.3 |
| Other operating revenues | 15.3 | 24.6 | (2.2) | 37.7 | 393.3 | 0.4 | (357.6) (1) | 73.8 |
| **Total operating revenues** | $ 5,647.1 | $ 1,357.1 | $ 426.0 | $ 7,430.2 | $ 495.9 | $ 4.4 | $ (407.4) | $ 7,523.1 |

(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:

| *(in millions)* | Year Ended December 31 2021 | 2020 | 2019 |
|---|---|---|---|
| Residential | **$ 1,768.0** | $ 1,743.9 | $ 1,608.6 |
| Small commercial and industrial | **1,415.7** | 1,325.9 | 1,384.6 |
| Large commercial and industrial | **931.9** | 821.5 | 871.9 |
| Other | **29.3** | 29.0 | 29.6 |
| **Total retail revenues** | **4,144.9** | 3,920.3 | 3,894.7 |
| Wholesale | **157.7** | 174.0 | 189.5 |
| Resale | **161.9** | 130.4 | 163.1 |
| Steam | **28.7** | 21.3 | 23.3 |
| Other utility revenues | **23.4** | 20.1 | 37.1 |
| **Total electric utility operating revenues** | **$ 4,516.6** | $ 4,266.1 | $ 4,307.7 |

#### 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, 2021** | | | | |
| Residential | **$ 928.9** | **$ 1,017.9** | **$ 241.2** | **$ 2,188.0** |
| Commercial and industrial | **472.1** | **302.1** | **129.9** | **904.1** |
| **Total retail revenues** | **1,401.0** | **1,320.0** | **371.1** | **3,092.1** |
| Transportation | **80.0** | **231.2** | **31.8** | **343.0** |
| Other utility revenues [1] | **9.3** | **79.1** | **91.1** | **179.5** |
| **Total natural gas utility operating revenues** | **$ 1,490.3** | **$ 1,630.3** | **$ 494.0** | **$ 3,614.6** |

| *(in millions)* | Wisconsin | Illinois | Other States | Total Natural Gas Utility Operating Revenues |
|---|---|---|---|---|
| **Year ended December 31, 2020** | | | | |
| Residential | $ 752.6 | $ 802.2 | $ 220.8 | $ 1,775.6 |
| Commercial and industrial | 338.1 | 221.0 | 115.8 | 674.9 |
| **Total retail revenues** | 1,090.7 | 1,023.2 | 336.6 | 2,450.5 |
| Transportation | 79.1 | 215.6 | 31.5 | 326.2 |
| Other utility revenues [1] | 25.8 | 29.1 | (7.1) | 47.8 |
| **Total natural gas utility operating revenues** | $ 1,195.6 | $ 1,267.9 | $ 361.0 | $ 2,824.5 |

| *(in millions)* | Wisconsin | Illinois | Other States | Total Natural Gas Utility Operating Revenues |
|---|---|---|---|---|
| **Year ended December 31, 2019** | | | | |
| Residential | $ 837.9 | $ 857.8 | $ 258.2 | $ 1,953.9 |
| Commercial and industrial | 419.9 | 261.7 | 148.7 | 830.3 |
| **Total retail revenues** | 1,257.8 | 1,119.5 | 406.9 | 2,784.2 |
| Transportation | 72.6 | 245.3 | 31.6 | 349.5 |
| Other utility revenues [1] | (6.3) | (32.4) | (26.9) | (65.6) |
| **Total natural gas utility operating revenues** | $ 1,324.1 | $ 1,332.4 | $ 411.6 | $ 3,068.1 |

(1) Includes the revenues subject to the purchased gas recovery mechanisms of our utilities. The amounts for 2021 reflect the higher natural gas costs that were incurred as a result of the extreme winter weather conditions in February 2021. As these amounts are billed to customers, they are reflected in retail revenues with an offsetting decrease in other utility revenues. See Note 26, Regulatory Environment, for more information. In addition to costs related to the extreme weather event, we incurred higher natural gas costs throughout 2021, compared with 2020, as a result of an increase in the price of natural gas.

**Other Natural Gas Operating Revenues**

We have other natural gas operating revenues from Bluewater, which is in our non-utility energy infrastructure segment. 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. All amounts associated with the service agreements with WE, WPS, and WG have been eliminated at the consolidated level.

**Other Non-Utility Operating Revenues**

Other non-utility operating revenues consist primarily of the following:

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions)*** | **2021** | **2020** | **2019** |
| Wind generation revenues | **$ 60.3** | $ 34.6 | $ 24.0 |
| We Power revenues | **23.3** | 22.9 | 25.4 |
| Appliance service revenues | **17.8** | 17.1 | 16.6 |
| Other | **0.1** | 1.7 | 4.2 |
| **Total other non-utility operating revenues** | **$ 101.5** | $ 76.3 | $ 70.2 |

## *Other Operating Revenues*

Other operating revenues consist primarily of the following:

| | Year Ended December 31 | | |
|---|---|---|---|
| ***(in millions)*** | **2021** | **2020** | **2019** |
| Late payment charges (1) | **$ 54.9** | $ 29.4 | $ 43.7 |
| Alternative revenues (2) | **21.2** | 38.8 | (9.6) |
| Other | **4.2** | 4.2 | 39.7 |
| **Total other operating revenues** | **$ 80.3** | $ 72.4 | $ 73.8 |

(1) The increase in late payment charges during 2021, compared with 2020, was a result of the expiration of various regulatory orders from our utility commissions in response to the COVID-19 pandemic, which included the suspension of late payment charges during a designated time period. See Note 26, Regulatory Environment, for more information.

The reduction in late payment charges in 2020, compared with 2019, was a result of various regulatory orders from our utility commissions in response to the COVID-19 pandemic, which included the suspension of late payment charges during a designated time period. PGL and NSG were authorized to implement a SPC rider for the recovery of these late payment charges related to COVID-19, thereby allowing them to record these late payment charges as alternative revenues. The total amount of late payment charges recorded as alternative revenues during the year ended December 31, 2020 was $8.5 million. See Note 26, Regulatory Environment, for more information.

(2) Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. Negative amounts can also result from revenues to be refunded to customers subject to decoupling mechanisms, wholesale true-ups, conservation improvement rider true-ups, and certain late payment charges, as discussed in Note 1(d), Operating Revenues.

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## 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, 2021 and 2020, 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, 2021** | | | | | | | |
| Accounts receivable and unbilled revenues | **$ 1,053.1** | **$ 523.1** | **$ 105.7** | **$ 1,681.9** | **$ 17.0** | **$ 5.1** | **$ 1,704.0** |
| Allowance for credit losses | **84.0** | **105.5** | **8.8** | **198.3** | **—** | **—** | **198.3** |
| **Accounts receivable and unbilled revenues, net [1]** | **$ 969.1** | **$ 417.6** | **$ 96.9** | **$ 1,483.6** | **$ 17.0** | **$ 5.1** | **$ 1,505.7** |
| | | | | | | | |
| Total accounts receivable, net – past due greater than 90 days [1] | **$ 46.5** | **$ 36.6** | **$ 3.4** | **$ 86.5** | **$ —** | **$ —** | **$ 86.5** |
| Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1] | **97.6 %** | **100.0 %** | **— %** | **94.8 %** | **— %** | **— %** | **94.8 %** |

| (in millions) | Wisconsin | Illinois | Other States | Total Utility Operations | Non-Utility Energy Infrastructure | Corporate and Other | WEC Energy Group Consolidated |
|---|---|---|---|---|---|---|---|
| **December 31, 2020** | | | | | | | |
| Accounts receivable and unbilled revenues | $ 899.8 | $ 393.9 | $ 79.8 | $ 1,373.5 | $ 45.0 | $ 4.4 | $ 1,422.9 |
| Allowance for credit losses | 102.1 | 111.6 | 6.4 | 220.1 | — | — | 220.1 |
| **Accounts receivable and unbilled revenues, net [1]** | $ 797.7 | $ 282.3 | $ 73.4 | $ 1,153.4 | $ 45.0 | $ 4.4 | $ 1,202.8 |
| | | | | | | | |
| Total accounts receivable, net – past due greater than 90 days [1] | $ 84.8 | $ 34.5 | $ 3.5 | $ 122.8 | $ — | $ — | $ 122.8 |
| Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1] | 97.6 % | 100.0 % | — % | 95.5 % | — % | — % | 95.5 % |

[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, 2021, $839.1 million, or 55.7%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses. In addition, we have received specific orders related to the deferral of certain costs (including credit losses) incurred as a result of the COVID-19 pandemic. The additional protections related to our accounts receivable and unbilled revenue balances provided by these orders are subject to prudency reviews and are still being assessed. They are not reflected in the percentages in the above tables or this note. See Note 26, Regulatory Environment, for more information on these orders.

A rollforward of the allowance for credit losses by reportable segment for the years ended December 31, 2021 and 2020, is included below:

| **Year Ended December 31, 2021** *(in millions)* | Wisconsin | Illinois | Other States | Total Utility Operations | Corporate and Other | WEC Energy Group Consolidated |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2020** | $ 102.1 | $ 111.6 | $ 6.4 | $ 220.1 | $ — | $ 220.1 |
| Provision for credit losses | **46.4** | **25.6** | **3.7** | **75.7** | **—** | **75.7** |
| Provision for credit losses deferred for future recovery or refund | **(16.6)** | **3.5** | **—** | **(13.1)** | **—** | **(13.1)** |
| Write-offs charged against the allowance | **(74.8)** | **(52.5)** | **(2.5)** | **(129.8)** | **—** | **(129.8)** |
| Recoveries of amounts previously written off | **26.9** | **17.3** | **1.2** | **45.4** | **—** | **45.4** |
| **Balance at December 31, 2021** | **$ 84.0** | **$ 105.5** | **$ 8.8** | **$ 198.3** | **$ —** | **$ 198.3** |

The decrease in the allowance for credit losses at December 31, 2021, compared to December 31, 2020, primarily related to normal collection practices resuming in April 2021 for our Wisconsin utilities and in June 2021 for our Illinois utilities. Across all of our reportable segments, higher year-over-year natural gas prices drove an increase in gross accounts receivable balances, partially offsetting the decrease in the allowance for credit losses attributed to collection efforts. See Note 26, Regulatory Environment, for more information.

| **Year Ended December 31, 2020** ***(in millions)*** | **Wisconsin** | **Illinois** | **Other States** | **Total Utility Operations** | **Corporate and Other** | **WEC Energy Group Consolidated** |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2019** | $ 59.9 | $ 75.9 | $ 4.1 | $ 139.9 | $ 0.1 | $ 140.0 |
| Provision for credit losses | 47.5 | 51.1 | 4.3 | 102.9 | — | 102.9 |
| Provision for credit losses deferred for future recovery or refund | 24.6 | 30.6 | — | 55.2 | — | 55.2 |
| Write-offs charged against the allowance | (65.9) | (63.0) | (3.4) | (132.3) | — | (132.3) |
| Recoveries of amounts previously written off | 36.0 | 17.0 | 1.4 | 54.4 | — | 54.4 |
| Sale of PDL residential solar facilities | — | — | — | — | (0.1) | (0.1) |
| **Balance at December 31, 2020** | $ 102.1 | $ 111.6 | $ 6.4 | $ 220.1 | $ — | $ 220.1 |

The increase in the allowance for credit losses at December 31, 2020, compared to December 31, 2019, was driven by higher past due accounts receivable balances at our utility segments, primarily related to residential customers. This increase in accounts receivable balances in arrears was driven by economic disruptions caused by the COVID-19 pandemic, including higher unemployment rates. Also, as a result of the COVID-19 pandemic and related regulatory orders we received, we were unable to disconnect any of our Wisconsin and Illinois customers during the year ended December 31, 2020.

## NOTE 6—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets were reflected on our balance sheets as of December 31:

| ***(in millions)*** | **2021** | **2020** | **See Note** |
|---|---|---|---|
| **Regulatory assets** [1] [2] | | | |
| Pension and OPEB costs [3] | **$ 802.3** | $ 1,101.6 | 20 |
| Plant retirement related items | **722.3** | 740.8 | |
| Environmental remediation costs [4] | **630.9** | 638.2 | 24 |
| Income tax related items | **458.8** | 454.6 | 16 |
| AROs | **194.2** | 181.3 | 9 |
| SSR [5] | **129.5** | 135.6 | 26 |
| Securitization | **100.7** | 105.2 | 23 |
| Energy costs recoverable through rate adjustments [6] | **85.4** | 1.1 | 1(d) |
| MERC extraordinary natural gas costs [7] | **59.7** | — | 26 |
| Uncollectible expense | **42.6** | 82.0 | 5 |
| Derivatives | **33.1** | 26.5 | 1(s) |
| Energy efficiency programs [8] | **22.0** | 7.3 | |
| Other, net | **85.6** | 69.9 | |
| **Total regulatory assets** | **$ 3,367.1** | $ 3,544.1 | |
| | | | |
| **Balance sheet presentation** | | | |
| Other current assets [6] | **$ 102.3** | $ 20.0 | |
| Regulatory assets | **3,264.8** | 3,524.1 | |
| **Total regulatory assets** | **$ 3,367.1** | $ 3,544.1 | |

[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 $30.9 million and $34.2 million at December 31, 2021 and 2020, respectively.

[2] As of December 31, 2021, we had $337.7 million of regulatory assets not earning a return, $14.3 million of regulatory assets earning a return based on short-term interest rates, and $129.5 million of regulatory assets earning a return based on long-term interest rates. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, energy costs recoverable through rate adjustments, MERC's extraordinary natural gas costs, uncollectible expense, our invested capital tax rider, COVID-19 deferred costs, and unamortized loss on reacquired debt. 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 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.

(4) As of December 31, 2021, we had made cash expenditures of $98.3 million related to these environmental remediation costs. The remaining $532.6 million represents our estimated future cash expenditures.

(5) The rate order WE received from the PSCW in December 2019 authorized recovery of the SSR regulatory asset over a 15-year period that began on January 1, 2020.

(6) The increase in these regulatory assets primarily relates to the high natural gas costs that were incurred as a result of the extreme winter weather conditions in February 2021. See Note 26, Regulatory Environment, for more information on our recovery efforts associated with these costs.

(7) Represents the extraordinary natural gas costs MERC incurred during February 2021 that are being recovered over 27 months, beginning in September 2021. See Note 26, Regulatory Environment, for more information on our recovery efforts associated with these costs.

(8) 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)* | 2021 | 2020 | See Note |
|---|---|---|---|
| **Regulatory liabilities** | | | |
| Income tax related items | **$ 1,998.5** | $ 2,137.7 | 16 |
| Removal costs [1] | **1,248.0** | 1,221.1 | |
| Pension and OPEB benefits [2] | **397.3** | 378.1 | 20 |
| Derivatives | **124.1** | 16.4 | 1(s) |
| Electric transmission costs [3] | **84.2** | 78.5 | |
| Uncollectible expense | **37.1** | 25.5 | 5 |
| Earnings sharing mechanisms | **28.4** | 36.9 | 26 |
| Energy costs refundable through rate adjustments | **13.7** | 59.9 | 1(d) |
| Other, net | **29.0** | 25.0 | |
| **Total regulatory liabilities** | **$ 3,960.3** | $ 3,979.1 | |
| | | | |
| **Balance sheet presentation** | | | |
| Other current liabilities | **$ 14.3** | $ 51.0 | |
| Regulatory liabilities | **3,946.0** | 3,928.1 | |
| **Total regulatory liabilities** | **$ 3,960.3** | $ 3,979.1 | |

(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) 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.

## Pleasant Prairie Power Plant

The Pleasant Prairie power plant was retired on April 10, 2018. The net book value of this plant was $585.7 million at December 31, 2021, representing book value less cost of removal and accumulated depreciation. In addition, previously deferred unprotected tax benefits from the Tax Legislation related to the unrecovered balance of this plant were $18.5 million. The net amount of $567.2 million was classified as a regulatory asset on our balance sheet at December 31, 2021 as a result of the retirement of the plant. This regulatory asset does not include certain other previously recorded deferred tax liabilities of $164.1 million related to the retired Pleasant Prairie power plant. Pursuant to its rate order issued by the PSCW in December 2019, WE will continue to amortize this regulatory asset on a straight-line basis through 2039, using the composite depreciation rates approved by the PSCW before this plant was retired. Amortization is included in depreciation and amortization in the income statement. WE has FERC approval to continue to collect the net book value of the Pleasant Prairie power plant using the approved composite depreciation rates, in addition to a return on the remaining net book value. Collection of the return of and on the net book value is no longer subject to refund as the FERC completed its prudency review and concluded that the retirement of this plant was prudent. WE received approval from the PSCW in December 2019 to collect a full return of the net book value of the Pleasant Prairie power plant, and a return on all but $100 million of the net book value. In accordance with its PSCW rate order received in December 2019, WE filed an application with the PSCW on July 20, 2020 requesting a financing order to securitize the remaining $100 million of the Pleasant Prairie power plant's book value, plus the carrying costs accrued on the $100 million during the securitization process and related fees. On November 17, 2020, the PSCW issued a written order approving this application and in May 2021 the securitization was completed. See Note 23, Variable Interest Entities, and Note 26, Regulatory Environment, for more information.

### Presque Isle Power Plant

Pursuant to MISO's April 2018 approval of the retirement of the PIPP, these units were retired on March 31, 2019. The net book value of the PIPP was $163.3 million at December 31, 2021, representing book value less cost of removal and accumulated depreciation. In addition, previously deferred unprotected tax benefits from the Tax Legislation related to the unrecovered balance of these units were $5.6 million. The net amount of $157.7 million was classified as a regulatory asset on our balance sheet at December 31, 2021 as a result of the retirement of the plant. This regulatory asset does not include certain other previously recorded deferred tax liabilities of $46.7 million related to the retired PIPP. After the retirement of the PIPP, a portion of the regulatory asset and related cost of removal reserve was transferred to UMERC for recovery from its retail customers. Effective with its rate order issued by the PSCW in December 2019, WE received approval to collect a return of and on its share of the net book value of the PIPP, and as a result, will continue to amortize the regulatory assets on a straight-line basis through 2037, using the composite depreciation rates approved by the PSCW before the units were retired. UMERC will also continue to amortize the regulatory assets on a straight-line basis using the composite depreciation rates approved by the PSCW before the units were retired. Amortization is included in depreciation and amortization in the income statement. UMERC will address the accounting and regulatory treatment related to the retirement of the PIPP with the MPSC in conjunction with a future rate case. WE has FERC approval to continue to collect the net book value of the PIPP using the approved composite depreciation rates, in addition to a return on the net book value. Based on a settlement agreement approved by the FERC, collection of the return of and on the net book value through WE's FERC-jurisdictional rates is no longer subject to refund.

### Pulliam Power Plant

In connection with a MISO ruling, WPS retired Pulliam Units 7 and 8 on October 21, 2018. The net book value of the Pulliam units was $38.0 million at December 31, 2021, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheet at December 31, 2021 as a result of the retirement of the plant. Effective with its rate order issued by the PSCW in December 2019, WPS received approval to collect a return of and on the entire net book value of the Pulliam units, and as a result, will continue to amortize this regulatory asset on a straight-line basis through 2031, using the composite depreciation rates approved by the PSCW before these generating units were retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the net book value of the Pulliam power plant using the approved composite depreciation rates, in addition to a return on the remaining net book value. FERC has completed its prudency review of Pulliam, concluding that the retirement of this plant was prudent.

### Edgewater Unit 4

The Edgewater 4 generating unit was retired on September 28, 2018. The net book value of the generating unit was $3.6 million at December 31, 2021, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheet at December 31, 2021 as a result of the retirement of the plant. Effective with its rate order issued by the PSCW in December 2019, WPS received approval to collect a return of and on the entire net book value of the Edgewater 4 generating unit, and as a result, will continue to amortize this regulatory asset on a straight-line basis through 2026, using the composite depreciation rates approved by the PSCW before this generating unit was retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the net book value of the Edgewater 4 generating unit using the approved composite depreciation rates, in addition to a return on the remaining net book value. FERC has completed its prudency review of Edgewater 4, concluding that the retirement of this plant was prudent.

## NOTE 7—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following at December 31:

| *(in millions)* | 2021 | 2020 |
|---|---|---|
| Electric – generation | **$ 6,981.4** | $ 7,015.3 |
| Electric – distribution | **7,854.7** | 7,455.5 |
| Natural gas – distribution, storage, and transmission | **13,526.6** | 12,730.0 |
| Property, plant, and equipment to be retired, net | **277.0** | — |
| Other | **2,212.6** | 1,896.1 |
| Less: Accumulated depreciation | **8,894.9** | 8,465.0 |
| Net | **21,957.4** | 20,631.9 |
| CWIP | **406.0** | 683.9 |
| Net utility and non-utility property, plant, and equipment | **22,363.4** | 21,315.8 |
| | | |
| We Power generation | **3,240.5** | 3,238.8 |
| Renewable generation | **1,837.5** | 1,213.3 |
| Natural gas storage | **289.9** | 250.0 |
| Net non-utility energy infrastructure | **5,367.9** | 4,702.1 |
| Corporate services | **188.7** | 212.3 |
| Other | **27.0** | 41.8 |
| Less: Accumulated depreciation | **994.4** | 899.7 |
| Net | **4,589.2** | 4,056.5 |
| CWIP | **29.8** | 335.1 |
| Net other property, plant, and equipment | **4,619.0** | 4,391.6 |
| | | |
| **Total property, plant, and equipment** | **$ 26,982.4** | $ 25,707.4 |

### Severance Liability for Plant Retirements

We have severance liabilities related to past and future plant retirements recorded in other current liabilities on our balance sheets. Activity related to these severance liabilities for the years ended December 31 was as follows:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Severance liability at January 1 | $ 0.7 | $ 2.1 | $ 15.7 |
| Severance expense | **4.6** | — | — |
| Severance payments | **(0.4)** | (0.1) | (7.2) |
| Other | **—** | (1.3) | (6.4) |
| **Total severance liability at December 31** | **$ 4.9** | $ 0.7 | $ 2.1 |

### Wisconsin Segment Plant to be Retired

#### *Columbia Units 1 and 2*

As a result of a MISO ruling received in June 2021, retirement of the jointly-owned Columbia generating units 1 and 2 became probable. Columbia generating units 1 and 2 are expected to be retired by the end of 2023 and 2024, respectively. The net book value of WPS's ownership share of unit 1 and unit 2 was $89.1 million and $187.9 million, respectively, at December 31, 2021. These amounts were classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW.

### Public Service Building

During a significant rain event in May 2020, an underground steam tunnel in downtown Milwaukee flooded and steam vented into WE’s PSB. The damage to the building from the flooding and steam was extensive and required significant repairs and restorations. As of December 31, 2021, WE had incurred $92.4 million of costs related to these repairs and restorations. In 2020, WE received

$20.0 million of insurance proceeds to cover a portion of these costs and wrote off $12.5 million of costs that we do not intend to seek recovery for through other operation and maintenance expense. Of the remaining $59.9 million of costs to be recovered, we will recover $41.0 million through insurance proceeds as a result of a settlement that was reached in February 2022, with the difference expected to be recovered through rates.

In June 2021, we received approval from the PSCW to restore the PSB and to defer the project costs, net of insurance proceeds, as a component of rate base. As such, and in light of the agreement with insurers noted above, we do not currently expect a significant impact to our future results of operations.

## NOTE 8—JOINTLY OWNED UTILITY FACILITIES

We Power and WPS hold joint ownership interests in certain electric generating facilities. They are entitled to their share of generating capability and output of each facility equal to their respective ownership interest. They pay their ownership share of additional construction costs and have supplied their own financing for all jointly owned projects. We record We Power's and WPS's proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets.

We Power leases its ownership interest in ER 1 and ER 2 to WE, and WE operates these units. WE and WPS record their respective share of fuel inventory purchases and operating expenses, unless specific agreements have been executed to limit their maximum exposure to additional costs. WE's and WPS's 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 at December 31, 2021 was as follows:

| | We Power | WPS | | | | |
|---|---|---|---|---|---|---|
| ***(in millions, except for percentages and MW)*** | **Elm Road Generating Station Units 1 and 2** | **Weston Unit 4** | **Columbia Energy Center Units 1 and 2** | **Forward Wind** | **Two Creeks [2]** | **Badger Hollow I [3]** |
| Ownership | 83.34 % | 70.0 % | 27.5 % | 44.6 % | 66.7 % | 66.7 % |
| Share of capacity (MW) [1] | 1,060.8 | 387.3 | 311.1 | 61.5 | 100.0 | 100.0 |
| In-service date | 2010 and 2011 | 2008 | 1975 and 1978 | 2008 | 2020 | 2021 |
| Property, plant, and equipment | $ 2,433.8 | $ 598.4 | $ 425.4 | $ 122.5 | $ 136.7 | $ 134.5 |
| Accumulated depreciation | $ (487.7) | $ (224.3) | $ (161.9) | $ (53.3) | $ (5.3) | $ (0.4) |
| CWIP | $ 11.1 | $ 3.8 | $ 3.9 | $ — | $ — | $ 0.1 |

(1) Capacity for our jointly-owned electric generation facilities, other than Forward Wind, Two Creeks, and Badger Hollow I 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 2022 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 Forward Wind is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds. Capacity for Two Creeks and Badger Hollow I is based on nameplate capacity, which is the maximum output that a generator should produce at continuous full power.

(2) Commercial operation was achieved in November 2020 for Two Creeks.

(3) Commercial operation was achieved in November 2021 for Badger Hollow I.

WE, along with an unaffiliated utility, received PSCW approval to construct Badger Hollow II, a solar project that will be located in Iowa County, Wisconsin. Once constructed, WE will own 66.7%, or 100 MW, of Badger Hollow II. Commercial operation is targeted for the first quarter of 2023. The CWIP balance for Badger Hollow II was $39.8 million as of December 31, 2021.

WPS, along with an unaffiliated utility, received PSCW approval to acquire the Red Barn Wind Park, a utility-scale wind-powered electric generating facility. The project will be located in Grant County, Wisconsin and once constructed, WPS will own 90.0%, or 82 MW of this project. Construction is expected to be completed by the end of 2022.

## 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 biomass and hydro generation facilities; the dismantling of wind generation projects; the dismantling of solar generation projects; the disposal of PCB-contaminated transformers; the closure of coal combustion residual landfills at certain generation facilities; and the removal of above ground 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 rate-making practices for retirement costs authorized by the applicable regulators.

WECI has also recorded AROs for the dismantling of our non-utility wind generation projects.

On our balance sheets, AROs are recorded within other long-term liabilities. The following table shows changes to our AROs during the years ended December 31:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Balance as of January 1 | **$ 513.5** | $ 483.5 | $ 461.4 |
| Accretion | **21.2** | 20.7 | 22.1 |
| Additions and revisions to estimated cash flows | **(53.9)** [1] | 39.7 [2] | 39.1 [3] |
| Liabilities settled | **(18.8)** | (30.4) | (39.1) |
| **Balance as of December 31** | **$ 462.0** | $ 513.5 | $ 483.5 |

[1] AROs decreased $152.0 million in 2021, due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL and NSG. Also in 2021, AROs increased $50.7 million due to new natural gas distribution lines being placed into service at PGL and NSG. AROs increased by $26.3 million as a result of AROs being recorded for the legal requirement to dismantle, at retirement, the Badger Hollow I solar generation project and the Tatanka Ridge and Jayhawk non-utility wind generation projects. AROs increased $7.8 million due to revisions made to removal estimates for wind generation projects at WE and WPS. AROs increased $6.8 million due to revisions made to the removal estimates for fly ash landfills and ash ponds at WPS.

[2] AROs increased $39.3 million in 2020, primarily due to new natural gas distribution lines being placed into service at PGL. Also in 2020, AROs increased by $8.5 million as a result of AROs being recorded for the legal requirement to dismantle, at retirement, the Two Creeks solar generation project. AROs decreased $9.2 million due to revisions made to estimated cash flows for the abatement of asbestos at WE.

[3] AROs increased $40.1 million in 2019, primarily due to new natural gas distribution lines being placed into service at PGL. Also in 2019, AROs increased $10.7 million as a result of AROs being recorded for the legal requirement to dismantle, at retirement, certain non-utility wind generation projects. AROs decreased $7.3 million due to revisions made to estimated cash flows for the abatement of asbestos at WE.

## 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, 2021. We had no changes to the carrying amount of goodwill during the years ended December 31, 2021 and 2020.

| *(in millions)* | Wisconsin | Illinois | Other States | Non-Utility Energy Infrastructure | Total |
|---|---|---|---|---|---|
| Goodwill balance [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, 2021.

During the third quarter of 2021, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2021. No impairments resulted from these tests.

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## Intangible Assets

At December 31, 2021, we had $5.7 million of indefinite-lived intangible assets primarily related to a MGU trade name obtained through an acquisition, which is included in other long-term assets on our balance sheets. We had no changes to the carrying amount of these intangible assets during the years ended December 31, 2021 and 2020.

## Intangible Liabilities

The intangible liabilities below were all obtained through acquisitions by WECI and are classified as other long-term liabilities on our balance sheets. See Note 2, Acquisitions, for more information.

| | December 31, 2021 | | | December 31, 2020 | | |
|---|---|---|---|---|---|---|
| *(in millions)* | **Gross Carrying Amount** | **Accumulated Amortization** | **Net Carrying Amount** | **Gross Carrying Amount** | **Accumulated Amortization** | **Net Carrying Amount** |
| PPAs [1] | **$ 87.9** | **$ (6.5)** | **$ 81.4** | $ 76.1 | $ — | $ 76.1 |
| Proxy revenue swap [2] | **7.2** | **(2.1)** | **5.1** | 7.2 | (1.3) | 5.9 |
| Interconnection agreements [3] | **4.7** | **(0.5)** | **4.2** | 5.1 | (0.3) | 4.8 |
| **Total intangible liabilities** | **$ 99.8** | **$ (9.1)** | **$ 90.7** | $ 88.4 | $ (1.6) | $ 86.8 |

[1] Represents PPAs related to the acquisition of Blooming Grove, Tatanka Ridge, and Jayhawk expiring between 2030 and 2032. The weighted-average remaining useful life of the PPAs is 11 years.

[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 seven 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 19 years.

Amortization related to these intangibles for the years ended December 31, 2021 and 2020, was $7.5 million and $0.8 million, respectively. Amortization for the year ended December 31, 2019 was not significant. Amortization for the next five years is estimated to be:

| | For the Years Ending December 31 | | | | |
|---|---|---|---|---|---|
| *(in millions)* | **2022** | **2023** | **2024** | **2025** | **2026** |
| Amortization to be recorded in operating revenues | $ 8.5 | $ 8.4 | $ 8.4 | $ 8.4 | $ 8.4 |
| Amortization to be recorded in 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)* | **2021** | **2020** | **2019** |
|---|---|---|---|
| Stock options | **$ 6.5** | $ 6.0 | $ 4.4 |
| Restricted stock | **6.1** | 7.4 | 7.1 |
| Performance units | **3.1** | 22.3 | 38.7 |
| Stock-based compensation expense | **$ 15.7** | $ 35.7 | $ 50.2 |
| Related tax benefit | **$ 4.3** | $ 9.8 | $ 13.8 |

Stock-based compensation costs capitalized during 2021, 2020, and 2019 were not significant.

### *Stock Options*

The following is a summary of our stock option activity during 2021:

| 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, 2021 | 2,887,460 | $ 64.13 | | |
| Granted | **530,612** | **$ 91.06** | | |
| Exercised | **(300,657)** | **$ 52.15** | | |
| Forfeited | **(5,508)** | **$ 83.51** | | |
| **Outstanding as of December 31, 2021** | **3,111,907** | **$ 69.84** | **6.2** | **$ 84.7** |
| **Exercisable as of December 31, 2021** | **1,737,283** | **$ 57.88** | **4.6** | **$ 68.1** |

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, 2021. This is calculated as the difference between our closing stock price on December 31, 2021, 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, 2021, 2020, and 2019 was $12.9 million, $47.1 million, and $62.4 million, respectively. The actual tax benefit from option exercises for the same periods was approximately $3.5 million, $12.9 million, and $17.1 million, respectively.

As of December 31, 2021, approximately $2.6 million of unrecognized compensation cost related to unvested and outstanding stock options was expected to be recognized over the next 1.6 years on a weighted-average basis.

During the first quarter of 2022, the Compensation Committee awarded 437,269 non-qualified stock options with a weighted-average exercise price of $96.04 and a weighted-average grant date fair value of $14.71 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 2021:

| Restricted Shares | Number of Shares | Weighted-Average Grant Date Fair Value |
|---|---|---|
| Outstanding and unvested as of January 1, 2021 | 101,087 | $ 83.28 |
| Granted | **69,681** | **$ 91.06** |
| Released | **(70,083)** | **$ 83.06** |
| Forfeited | **(1,624)** | **$ 84.43** |
| **Outstanding and unvested as of December 31, 2021** | **99,061** | **$ 88.89** |

The intrinsic value of restricted stock released was $6.5 million, $11.1 million, and $13.4 million for the years ended December 31, 2021, 2020, and 2019, respectively. The actual tax benefit from released restricted shares for the same years was $1.8 million, $3.1 million, and $3.7 million, respectively.

As of December 31, 2021, approximately $3.2 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 2022, the Compensation Committee awarded 72,211 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 $96.04 per share.

### *Performance Units*

During 2021, 2020, and 2019, the Compensation Committee awarded 152,382; 153,465; and 148,036 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $27.7 million, $34.5 million, and $18.7 million were settled during 2021, 2020, and 2019, respectively. The actual tax benefit from the distribution of performance units for the same years was $6.8 million, $8.4 million, and $4.4 million, respectively.

At December 31, 2021, we had 449,290 performance units outstanding, including dividend equivalents. A liability of $21.3 million was recorded on our balance sheet at December 31, 2021 related to these outstanding units. As of December 31, 2021, approximately $10.8 million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 2.0 years on a weighted-average basis.

During the first quarter of 2022, we settled performance units with an intrinsic value of $15.7 million. The actual tax benefit from the distribution of these awards was $3.8 million. In January 2022, the Compensation Committee also awarded 171,492 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 52.5%. 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.

WECI Wind Holding I's long-term debt obligations contain various conditions that must be met prior to WECI Wind Holding I making any cash distributions. Included in these provisions is a requirement to maintain a debt service coverage ratio of 1.2 or greater for the 12-month period prior to the distribution.

WEC Energy Group and Integrys have the option to defer interest payments on their junior subordinated notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which they defer interest payments, they may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, their respective 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, 2021, restricted net assets of our consolidated subsidiaries totaled approximately $9.0 billion. Our equity in undistributed earnings of investees accounted for by the equity method was approximately $412 million.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

## Share Purchases

We have instructed our independent agents to purchase shares on the open market to fulfill obligations under various stock-based employee benefit and compensations plans and to provide shares to participants in our dividend reinvestment and stock purchase plan. As a result, no new shares of common stock were issued in 2021, 2020, or 2019.

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)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Shares purchased | **0.4** | 1.0 | 1.8 |
| Cost of shares purchased | **$ 33.1** | $ 99.2 | $ 140.1 |

## Common Stock Dividends

During the year ended December 31, 2021, our Board of Directors declared common stock dividends which are summarized below:

| Date Declared | Date Payable | Per Share | Period |
|---|---|---|---|
| January 21, 2021 | March 1, 2021 | $0.6775 | First quarter |
| April 15, 2021 | June 1, 2021 | $0.6775 | Second quarter |
| July 15, 2021 | September 1, 2021 | $0.6775 | Third quarter |
| October 21, 2021 | December 1, 2021 | $0.6775 | Fourth quarter |

On January 20, 2022, our Board of Directors declared a quarterly cash dividend of $0.7275 per share, which equates to an annual dividend of $2.91 per share. The dividend is payable on March 1, 2022, to shareholders of record on February 14, 2022. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

## NOTE 12—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2021 and 2020:

| *(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)* | 2021 | 2020 |
|---|---|---|
| **Commercial paper** | | |
| Amount outstanding at December 31 | **$ 1,896.1** | $ 1,436.9 |
| Average interest rate on amounts outstanding at December 31 | **0.26 %** | 0.21 % |
| **Term loan** | | |
| Amount outstanding at December 31 | **$ —** | $ 340.0 |
| Average interest rate on amounts outstanding at December 31 | **N/A** | 0.99 % |
| **Operating expense loans** | | |
| Amount outstanding at December 31 [(1)] | **$ 0.9** | $ — |

[(1)] Coyote Ridge and Tatanka Ridge entered into operating expense loans. In accordance with their limited liability company operating agreements, they received loans from their owners in proportion to their ownership interests.

Our average amount of commercial paper borrowings based on daily outstanding balances during 2021, was $1,480.0 million with a weighted-average interest rate during the period of 0.18%.

In order to enhance our liquidity position in response to the COVID-19 pandemic, in March 2020, WEC Energy Group entered into a $340.0 million 364-day term loan. In March 2021, we repaid the term loan using the net proceeds from the issuance of our 0.80% Senior Notes. See Note 14, Long-Term Debt, for more information.

WEC Energy Group, WE, WPS, WG, and PGL 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, 2021, 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 | 2021 |
|---|---|---|
| Revolving credit facility (WEC Energy Group) [(1)] | September 2026 | **$ 1,500.0** |
| Revolving credit facility (WE) [(1)] | September 2026 | **500.0** |
| Revolving credit facility (WPS) [(2)] | October 2022 | **400.0** |
| Revolving credit facility (WG) [(1)] | September 2026 | **350.0** |
| Revolving credit facility (PGL) [(1)] | September 2026 | **350.0** |
| **Total short-term credit capacity** | | **$ 3,100.0** |
| | | |
| Less: | | |
| Letters of credit issued inside credit facilities | | **$ 2.3** |
| Commercial paper outstanding | | **1,896.1** |
| **Available capacity under existing facilities** | | **$ 1,201.6** |

[(1)] In September 2021, WEC Energy Group increased its credit facility to $1,500.0 million, and each of WEC Energy Group, WE, WG, and PGL extended the maturities of their credit facilities to September 2026.

[(2)] WPS intends to request approval from the PSCW to extend the maturity of its credit facility to September 2026. Lenders have agreed to the extension, subject to WPS's receipt of PSCW approval.

Each of the revolving credit facilities has a renewal provision for two extensions, subject to lender approval. Each extension is for a period of one year.

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 (excluding finance leases) as of December 31:

| | | 2021 | | 2020 | |
|---|---|---|---|---|---|
| *(in millions)* | Maturity Date | Weighted Average Interest Rate | Balance | Weighted Average Interest Rate | Balance |
| WEC Energy Group Senior Notes (unsecured) [1] | 2023-2033 | **1.67 %** | **$ 3,070.0** | 2.03 % | $ 2,270.0 |
| WEC Energy Group Junior Notes (unsecured) [1] [2] | 2067 | **2.27 %** | **500.0** | 3.65 % | 500.0 |
| WE Debentures (unsecured) | 2024-2095 | **4.13 %** | **2,785.0** | 4.26 % | 2,785.0 |
| WEPCo Environmental Trust (secured, nonrecourse) [6] [9] | 2022-2035 | **1.58 %** | **114.7** | N/A | — |
| WPS Senior Notes (unsecured) | 2028-2051 | **3.89 %** | **1,675.0** | 4.04 % | 1,625.0 |
| WG Debentures (unsecured) | 2024-2046 | **3.35 %** | **790.0** | 3.65 % | 640.0 |
| Integrys Junior Notes (unsecured) [3] | 2073 | **6.00 %** | **221.4** | 6.00 % | 400.0 |
| PGL First and Refunding Mortgage Bonds (secured) [4] | 2024-2047 | **3.31 %** | **1,870.0** | 3.45 % | 1,670.0 |
| NSG First Mortgage Bonds (secured) [5] | 2027-2043 | **3.56 %** | **157.0** | 3.81 % | 132.0 |
| MERC Senior Notes (unsecured) | 2025-2047 | **3.04 %** | **210.0** | 3.27 % | 170.0 |
| MGU Senior Notes (unsecured) | 2025-2047 | **3.18 %** | **150.0** | 3.18 % | 150.0 |
| UMERC Senior Notes (unsecured) | 2029 | **3.26 %** | **160.0** | 3.26 % | 160.0 |
| Bluewater Gas Storage Senior Notes (unsecured) [6] | 2022-2047 | **3.76 %** | **115.2** | 3.76 % | 117.8 |
| ATC Holding Senior Notes (unsecured) | 2025-2030 | **4.05 %** | **475.0** | 4.05 % | 475.0 |
| We Power Subsidiaries Notes (secured, nonrecourse) [6] [7] | 2022-2041 | **5.60 %** | **934.7** | 5.59 % | 970.8 |
| WECC Notes (unsecured) | 2028 | **6.94 %** | **50.0** | 6.94 % | 50.0 |
| WECI Wind Holding I Senior Notes (secured, nonrecourse) [6] [8] | 2022-2032 | **2.75 %** | **374.6** | 2.75 % | 413.6 |
| **Total** | | | **13,652.6** | | 12,529.2 |
| Integrys acquisition fair value adjustment | | | **2.9** | | 8.4 |
| Jayhawk acquisition | | | **7.3** | | — |
| Unamortized debt issuance costs | | | **(77.7)** | | (65.2) |
| Unamortized discount, net and other | | | **(21.7)** | | (21.9) |
| **Total long-term debt, including current portion** [10] | | | **13,563.4** | | 12,450.5 |
| Current portion of long-term debt | | | **(91.0)** | | (777.7) |
| **Total long-term debt** | | | **$ 13,472.4** | | $ 11,672.8 |

[1] In connection with our outstanding 2007 Junior Notes, we executed an RCC, which we amended on June 29, 2015, for the benefit of persons that buy, hold, or sell a specified series of our long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease, or purchase, and that our subsidiaries may not purchase, any 2007 Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, we have received a specified amount of proceeds from the sale of qualifying securities.

[2] Variable interest rate reset quarterly. The rates were 2.27% and 2.33% as of December 31, 2021 and 2020, respectively. On July 12, 2018, we executed two interest rate swaps that provided a fixed rate of 4.9765% on $250.0 million of the outstanding notes. On November 15, 2021, the interest rate swaps expired. At December 31, 2020, the effective rate of 3.65% was blended rates of the variable and fixed portions. See Note 18, Derivative Instruments, for more information on the two interest rate swaps.

[3] The terms of Integrys's 2013 Junior Notes provide that, effective August 2023, they will bear interest at the three-month LIBOR plus 322 basis points and will reset quarterly.

[4] 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.

[5] 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.

(6) The long-term debt of Bluewater, WECI Wind Holding I, WEPCo Environmental Trust, and We Power's subsidiaries requires periodic principal payments.

(7) 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.

(8) 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.

(9) 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.

(10) The amount of long-term debt on our balance sheets includes finance lease obligations of $129.7 million and $63.4 million at December 31, 2021 and 2020, respectively.

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

## WEC Energy Group, Inc.

In March 2021, we issued $600.0 million of 0.80% Senior Notes due March 15, 2024, and used the net proceeds to repay the $340.0 million 364-day term loan entered into in March 2020 and for general corporate purposes.

In December 2021, we issued $500.0 million of 2.20% Senior Notes due December 15, 2028, and used the net proceeds to repay short-term debt and for other general corporate purposes.

In December 2021, we redeemed $300.0 million of the $420.0 million outstanding of our 3.55% Senior Notes due June 15, 2025 with the proceeds we received from the issuance of $500 million of 2.20% Senior Notes due December 15, 2028. As a result of the redemption prior to maturity, we recognized a $23.1 million loss on early extinguishment of debt. The loss is comprised of the make-whole premium associated with the early redemption and the write-off of the related unamortized debt discount and debt issuance costs as of the redemption date.

## Wisconsin Electric Power Company

In June 2021, WE issued $300.0 million of 1.70% Debentures due June 15, 2028, and used the net proceeds to redeem early all $300.0 million outstanding of its 2.95% Debentures due September 15, 2021 at par.

## WEPCo Environmental Trust Finance I, LLC

In May 2021, WEPCo Environmental Trust, a special purpose entity formed by WE, issued $118.8 million of 1.578% ETBs due December 15, 2035, and used the net proceeds to purchase environmental control property from WE. Semiannual principal and interest payments began December 15, 2021, and the ETBs are expected to be fully repaid by December 15, 2033. The ETBs have a final maturity date of December 15, 2035. See Note 23, Variable Interest Entities, for more information on WEPCo Environmental Trust.

## Wisconsin Public Service Corporation

In November 2021, WPS issued $450.0 million of 2.85% Senior Notes due December 1, 2051, and intends to allocate an amount equal to the net proceeds for the construction and development of eligible green expenditures, which include existing and new expenditures for the acquisition, construction and development of wind and solar electric generating facilities and related energy storage assets.

In November 2021, WPS's $400.0 million 3.35% Senior Notes due November 21, 2021, matured, and the outstanding principal was paid with proceeds received from the issuance of the $450.0 million 2.85% Senior Notes Due December 1, 2051, pending their allocation to the payment or reimbursement of eligible green expenditures.

### Wisconsin Gas LLC

In November 2021, WG issued $150.0 million of 2.07% Debentures due December 1, 2028, and used the net proceeds to repay short-term debt and for other general corporate purposes.

### Integrys Holding, Inc.

In October 2021, pursuant to a tender offer, Integrys purchased $178.6 million aggregate principal amount of the $400.0 million outstanding of its 2013 Junior Notes for $196.4 million (which includes payment of accrued interest) with proceeds received from WEC Energy Group issuing commercial paper. Integrys recorded a $13.2 million loss related to the early settlement.

### The Peoples Gas Light and Coke Company

In November 2021, PGL issued $200.0 million of 2.20% Bonds, Series LLL due November 15, 2028, and used the net proceeds for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

### North Shore Gas Company

In November 2021, NSG issued $25.0 million of 2.20% Bonds, Series S due November 15, 2028, and used the net proceeds for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

### Minnesota Energy Resources Corporation

In November 2021, MERC issued $40.0 million of 2.07% Senior Notes due December 1, 2028, and used the net proceeds to repay intercompany short-term debt to its parent, Integrys, and for other general corporate purposes.

### Maturities of Long-Term Debt Outstanding

The following table shows the long-term debt securities (excluding finance leases) maturing within one year of December 31, 2021:

| *(in millions)* | Interest Rate | Maturity Date [1] | Principal Amount |
|---|---|---|---|
| WEPCo Environmental Trust (secured, nonrecourse) | 1.58% | Semi-annually | $ 8.8 |
| Bluewater Gas Storage Senior Notes (unsecured) | 3.76% | Semi-annually | 2.7 |
| We Power Subsidiaries Notes – PWGS (secured, nonrecourse) | 4.91% | Monthly | 7.2 |
| We Power Subsidiaries Notes – ERGS (secured, nonrecourse) | 5.209% | Semi-annually | 13.9 |
| We Power Subsidiaries Notes – ERGS (secured, nonrecourse) | 4.673% | Semi-annually | 10.7 |
| We Power Subsidiaries Notes – PWGS (secured, nonrecourse) | 6.00% | Monthly | 6.2 |
| WECI Wind Holding I Senior Notes (secured, nonrecourse) | 2.75% | Semi-annually | 41.5 |
| Total | | | $ 91.0 |

(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 (excluding obligations under finance leases) as of December 31, 2021:

| *(in millions)* | Payments |
|---|---|
| 2022 | $ 91.0 |
| 2023 | 793.8 |
| 2024 | 1,222.7 |
| 2025 | 865.9 |
| 2026 | 104.2 |
| Thereafter | 10,575.0 |
| **Total** | $ 13,652.6 |

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

### Obligations Under Operating Leases

We have recorded right of use assets and lease liabilities 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, though April 2029.
- Land we are leasing related to our Rothschild biomass plant through June 2051.
- Land we are leasing related to our Solar Now projects.

The operating leases generally require us to pay property taxes, insurance premiums, and operating and maintenance costs associated with the leased property. Many of our leases contain options to renew past the initial term, as set forth in the lease agreement.

### Obligations Under Finance Leases

In accordance with the Regulated Operations - Leases Topic of the FASB ASC, the timing of lease expense recognized at our regulated entities resembles the expense recognition pattern of an operating lease, as the amortization of the right of use assets is modified from what would typically be recorded for a finance lease. We record the difference between the minimum lease payments and the sum of imputed interest and unadjusted amortization costs calculated under the finance lease accounting rules as a regulatory asset on our balance sheets.

#### *Power Purchase Commitment*

In 1997, WE entered into a 25-year PPA with LSP-Whitewater Limited Partnership. The contract, for 236.5 MW of firm capacity from a natural gas-fired cogeneration facility, includes zero minimum energy requirements. The PPA expires on May 31, 2022; however, in November 2021, WE entered into a tolling agreement with LSP-Whitewater Limited Partnership that commences on June 1, 2022. Concurrent with the execution of the tolling agreement, WE and WPS entered into an asset purchase agreement to acquire the natural gas-fired cogeneration facility for $72.7 million. The asset purchase agreement is subject to regulatory approval, which was requested from the PSCW in December 2021. We expect to receive approval from the PSCW by the end of 2022, and the sale is expected to close in January 2023. The tolling agreement extends until the earlier of the closing of the asset purchase or December 31, 2022. As a result, we are amortizing the leases through December 31, 2022.

These combined transactions resulted in a lease modification whereby we were required to reassess the lease classification and remeasure the right of use asset and corresponding lease liability. The lease classification did not change as a result of the modification. Due to the execution of the asset purchase agreement, it is now reasonably certain that we will exercise the purchase option at the end of the extended lease term. Therefore, we included the estimated purchase option and the lease payments resulting from the tolling agreement in our remeasurement of the right of use asset and corresponding lease liability.

Our obligation under this finance lease as of December 31, 2021 and 2020, was $78.4 million and $12.1 million, respectively, and will decrease to zero over the remaining life of the lease.

### *Two Creeks Solar Park*

Related to its investment in Two Creeks, WPS, along with an unaffiliated utility, entered into several land leases in Manitowoc County, Wisconsin that commenced in the third quarter of 2019. The leases with unaffiliated parties are for a total of approximately 600 acres of land. Each lease has an initial term of 30 years with two optional 10-year extensions. We expect the two optional extensions to be exercised, and, as a result, the land leases are being amortized over the 50-year extended term of the leases. The lease payments are being recovered through rates. After achieving commercial operation in November 2020, the lease liability was remeasured as a result of finalizing the total acres being leased.

Our total obligation under the finance leases for Two Creeks as of December 31, 2021 and 2020, was $9.8 million and $7.9 million, respectively, and will decrease to zero over the remaining lives of the leases.

### *Badger Hollow Solar Park I*

Related to its investment in Badger Hollow I, WPS, along with an unaffiliated utility, entered into several land leases in Iowa County, Wisconsin that commenced in the third quarter of 2019. The leases are for a total of approximately 1,300 acres of land. Each lease has an initial construction term that ends upon achieving commercial operation, then automatically extends for 25 years with an option for an additional 25-year extension. We expect the optional extension to be exercised, and, as a result, the land leases are being amortized over the extended term of the leases. The lease payments will be recovered through rates. Upon achieving commercial operation in November 2021, the lease liability was remeasured as a result of finalizing the total acres being leased.

Our total obligation under the finance leases for Badger Hollow I as of December 31, 2021 and 2020, was $17.6 million and $20.3 million, respectively, and will decrease to zero over the remaining lives of the leases.

### *Badger Hollow Solar Park II*

Related to its investment in Badger Hollow II, WE, along with an unaffiliated utility, entered into several land leases in Iowa County, Wisconsin that commenced in the second quarter of 2020. The leases are for a total of approximately 1,500 acres of land. Each lease has an initial construction term that ends upon achieving commercial operation, then automatically extends for 25 years with an option for an additional 25-year extension. We expect the optional extension to be exercised, and, as a result, the land leases are being amortized over the extended term of the leases. The lease payments will be recovered through rates.

Our total obligation under the finance leases for Badger Hollow II as of December 31, 2021 and 2020, was $23.6 million and $23.1 million, respectively, and will decrease to zero over the remaining lives of the leases.

## 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)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Finance lease expense | | | |
| Amortization of right of use assets [(1)] | **$ 8.1** | $ 6.3 | $ 4.9 |
| Interest on lease liabilities [(2)] | **1.6** | 2.5 | 3.3 |
| Operating lease expense [(3)] | **3.4** | 5.4 | 5.5 |
| Short-term lease expense [(3)] | **0.2** | 0.3 | 0.6 |
| **Total lease expense** | **$ 13.3** | $ 14.5 | $ 14.3 |
| | | | |
| **Other information** | | | |
| Cash paid for amounts included in the measurement of lease liabilities | | | |
| Operating cash flows from finance leases | **$ 1.6** | $ 2.5 | $ 3.3 |
| Operating cash flows from operating leases | **$ 5.3** | $ 6.7 | $ 6.0 |
| Financing cash flows from finance leases | **$ 8.1** | $ 6.3 | $ 4.9 |
| Non-cash activities: | | | |
| Right of use assets obtained in exchange for finance lease liabilities | **$ 73.6** | $ 22.8 | $ 27.2 |
| Right of use assets obtained in exchange for operating lease liabilities | **$ 0.5** | $ — | $ 49.0 |
| | | | |
| Weighted-average remaining lease term – finance leases | **20.5 years** | 41.5 years | 31.5 years |
| Weighted-average remaining lease term – operating leases | **12.5 years** | 13.0 years | 12.9 years |
| | | | |
| Weighted-average discount rate – finance lease [(4)] | **2.4 %** | 4.9 % | 6.7 % |
| Weighted average discount rate – operating leases [(4)] | **3.4 %** | 3.4 % | 4.4 % |

(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 operation and maintenance expense.

(4) Because our leases do not provide an implicit rate of return, we used 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 lease right of use assets, which were included in property, plant, and equipment on our balance sheets at December 31:

| *(in millions)* | 2021 | 2020 |
|---|---|---|
| **Power purchase commitment** | | |
| Under finance leases | **$ 214.4** | $ 140.3 |
| Accumulated amortization | **(137.7)** | (132.3) |
| **Total power purchase commitment** | **$ 76.7** | $ 8.0 |
| | | |
| **Two Creeks land leases** | | |
| Under finance leases | **$ 9.6** | $ 7.7 |
| Accumulated amortization | **(0.4)** | (0.2) |
| **Total Two Creeks land leases** | **$ 9.2** | $ 7.5 |
| | | |
| **Badger Hollow I land leases** | | |
| Under finance leases | **$ 16.6** | $ 19.5 |
| Accumulated amortization | **(0.9)** | (0.6) |
| **Total Badger Hollow I land leases** | **$ 15.7** | $ 18.9 |
| | | |
| **Badger Hollow II land leases** | | |
| Under finance leases | **$ 22.8** | $ 22.8 |
| Accumulated amortization | **(0.7)** | (0.2) |
| **Total Badger Hollow II land leases** | **$ 22.1** | $ 22.6 |
| | | |
| **Other, net** | **$ 0.3** | $ — |
| **Total finance lease right of use assets, net** | **$ 124.0** | $ 57.0 |

Right of use assets related to operating leases were $19.5 million and $20.7 million at December 31, 2021 and 2020, respectively, and were included in other long-term assets on our balance sheets.

Future minimum lease payments under our operating and finance leases and the present value of our net minimum lease payments as of December 31, 2021, were as follows:

| *(in millions)* | Total Operating Leases | Power Purchase Commitment | Two Creeks | Badger Hollow I | Badger Hollow II | Other | Total Finance Leases |
|---|---|---|---|---|---|---|---|
| 2022 | $ 4.7 | $ 79.0 | $ 0.2 | $ 0.5 | $ 0.3 | $ — | $ 80.0 |
| 2023 | 4.5 | — | 0.2 | 0.5 | 0.7 | — | 1.4 |
| 2024 | 4.3 | — | 0.2 | 0.5 | 0.7 | — | 1.4 |
| 2025 | 3.8 | — | 0.2 | 0.5 | 0.7 | — | 1.4 |
| 2026 | 3.9 | — | 0.3 | 0.5 | 0.7 | — | 1.5 |
| Thereafter | 20.8 | — | 21.7 | 39.3 | 54.3 | 0.6 | 115.9 |
| Total minimum lease payments | 42.0 | 79.0 | 22.8 | 41.8 | 57.4 | 0.6 | 201.6 |
| Less: Interest | (9.2) | (0.6) | (13.0) | (24.2) | (33.8) | (0.3) | (71.9) |
| Present value of minimum lease payments | 32.8 | 78.4 | 9.8 | 17.6 | 23.6 | 0.3 | 129.7 |
| Less: Short-term lease liabilities | (3.7) | (78.4) | — | — | — | — | (78.4) |
| **Long-term lease liabilities** | $ 29.1 | $ — | $ 9.8 | $ 17.6 | $ 23.6 | $ 0.3 | $ 51.3 |

Short-term and long-term lease liabilities related to operating leases were included in other current liabilities and other long-term liabilities on the balance sheets, respectively. Short-term and long-term lease liabilities related to our finance leases were included in current portion of long-term debt and long-term debt on the balance sheets, respectively.

As of February 24, 2022, we have not entered into any material leases that have not yet commenced.

## NOTE 16—INCOME TAXES

### Income Tax Expense

The following table is a summary of income tax expense for the years ended December 31:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Current tax expense (benefit) | **$ 93.9** | $ 49.2 | $ (37.9) |
| Deferred income taxes, net | **111.0** | 182.2 | 167.7 |
| ITCs | **(4.6)** | (3.5) | (4.8) |
| **Total income tax expense** | **$ 200.3** | $ 227.9 | $ 125.0 |

### 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:

| | 2021 | | 2020 | | 2019 | |
|---|---|---|---|---|---|---|
| *(in millions)* | Amount | Effective Tax Rate | Amount | Effective Tax Rate | Amount | Effective Tax Rate |
| Statutory federal income tax | **$ 315.1** | **21.0 %** | $ 299.9 | 21.0 % | $ 264.4 | 21.0 % |
| State income taxes net of federal tax benefit | **96.1** | **6.4 %** | 90.5 | 6.3 % | 80.4 | 6.4 % |
| Wind PTCs | **(81.3)** | **(5.4) %** | (51.5) | (3.6) % | (34.1) | (2.7) % |
| Federal excess deferred tax amortization – Wisconsin unprotected (1) | **(77.9)** | **(5.2) %** | (57.6) | (4.0) % | — | — % |
| Federal excess deferred tax amortization (2) | **(37.3)** | **(2.5) %** | (36.7) | (2.6) % | (34.9) | (2.8) % |
| ITC restored | **(4.6)** | **(0.3) %** | (3.5) | (0.2) % | (4.8) | (0.4) % |
| AFUDC – Equity | **(3.8)** | **(0.3) %** | (4.4) | (0.3) % | (3.0) | (0.2) % |
| Excess tax benefits – stock options | **(3.2)** | **(0.2) %** | (12.3) | (0.9) % | (15.8) | (1.3) % |
| Tax repairs (3) | **4.0** | **0.3 %** | 3.3 | 0.2 % | (122.8) | (9.8) % |
| Other, net | **(6.8)** | **(0.4) %** | 0.2 | — % | (4.4) | (0.3) % |
| **Total income tax expense** | **$ 200.3** | **13.4 %** | $ 227.9 | 15.9 % | $ 125.0 | 9.9 % |

(1) In accordance with the rate order received from the PSCW in December 2019, our Wisconsin utilities are amortizing these unprotected deferred tax benefits over periods ranging from two years to four years, to reduce near-term rate impacts to their customers. 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.

(2) The Tax Legislation required our regulated utilities to remeasure their deferred income taxes and we began to amortize the resulting excess protected 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.

(3) In accordance with a settlement agreement with the PSCW, WE flowed through the tax benefit of its repair related deferred tax liabilities in 2018 and 2019, to maintain certain regulatory asset balances at their December 31, 2017 levels. The flow through treatment of the repair related deferred tax liabilities offset the negative income statement impact of holding the regulatory assets level, resulting in no impact to net income. In 2020, in accordance with the settlement agreement, WE started collecting the payback of the tax repairs benefit that was flowed through to customers. Customers will pay back all of the benefits over the next fifty years.

See Note 26, Regulatory Environment, for more information about the impact of the Tax Legislation and the Wisconsin rate orders.

## Deferred Income Tax Assets and Liabilities

The components of deferred income taxes as of December 31 were as follows:

| *(in millions)* | 2021 | 2020 |
|---|---|---|
| **Deferred tax assets** | | |
| Tax gross up – regulatory items | **$ 469.5** | $ 497.6 |
| Future tax benefits | **104.6** | 102.5 |
| Deferred revenues | **97.8** | 104.2 |
| Other | **205.9** | 197.2 |
| **Total deferred tax assets** | **877.8** | 901.5 |
| Valuation allowance | **(1.2)** | (2.3) |
| **Net deferred tax assets** | **$ 876.6** | $ 899.2 |
| | | |
| **Deferred tax liabilities** | | |
| Property-related | **$ 3,909.0** | $ 3,721.0 |
| Investment in affiliates | **648.6** | 647.2 |
| Deferred costs – plant retirements | **223.9** | 255.4 |
| Employee benefits and compensation | **170.6** | 148.2 |
| Other | **233.0** | 187.2 |
| **Total deferred tax liabilities** | **5,185.1** | 4,959.0 |
| **Deferred tax liability, net** | **$ 4,308.5** | $ 4,059.8 |

Consistent with rate-making 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, 2021 and 2020 are summarized in the tables below:

| **2021**<br>*(in millions)* | Gross Value | Deferred Tax Effect | Valuation Allowance | Earliest Year of Expiration |
|---|---|---|---|---|
| **Future tax benefits as of December 31, 2021** | | | | |
| Federal tax credit | **$ —** | **$ 91.5** | **$ —** | **2041** |
| State net operating loss | **72.0** | **4.4** | **(1.2)** | **2030** |
| Other state benefits | **—** | **8.7** | **—** | **2023** |
| **Balance as of December 31, 2021** | **$ 72.0** | **$ 104.6** | **$ (1.2)** | |

| **2020**<br>*(in millions)* | Gross Value | Deferred Tax Effect | Valuation Allowance | Earliest Year of Expiration |
|---|---|---|---|---|
| Future tax benefits as of December 31, 2020 | | | | |
| Federal tax credit | $ — | $ 89.1 | $ — | 2040 |
| State net operating loss | 88.8 | 5.5 | (2.3) | 2030 |
| Other state benefits | — | 7.9 | — | 2023 |
| Balance as of December 31, 2020 | $ 88.8 | $ 102.5 | $ (2.3) | |

## Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Balance as of January 1 | **$ 11.9** | $ 17.9 | $ 20.0 |
| Additions for tax positions of prior years | **—** | 1.6 | 1.9 |
| Additions based on tax positions related to the current year | **1.6** | 0.1 | 0.2 |
| Reductions for tax positions of prior years | **(6.7)** | (7.7) | (4.2) |
| **Balance as of December 31** | **$ 6.8** | $ 11.9 | $ 17.9 |

The amount of unrecognized tax benefits as of December 31, 2021 and 2020, excludes deferred tax assets related to uncertainty in income taxes of $1.2 million and $1.9 million, respectively. As of December 31, 2021 and 2020, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $5.7 million and $10.1 million, respectively.

Interest accrued related to unrecognized tax benefits is as follows:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Balance as of January 1 | $ 0.5 | $ 0.8 | $ 0.7 |
| Interest expense (income) related to unrecognized tax benefits | **(0.4)** | (0.3) | 0.1 |
| **Balance as of December 31** | **$ 0.1** | $ 0.5 | $ 0.8 |

For the years ended December 31, 2021, 2020, and 2019, we recognized no penalties related to unrecognized tax benefits in our consolidated income statements. At December 31, 2021 and 2020, we had no amounts accrued for penalties related to unrecognized tax benefits.

Although analysis of our unrecognized tax benefits is ongoing, the potential estimated decrease in the total amounts of unrecognized tax benefits within the next 12 months is approximately $2.1 million associated with statutes of limitations on certain tax years. We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

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, 2021, with a few exceptions, we were subject to examination by federal and state or local tax authorities for the 2017 through 2021 tax years in our major operating jurisdictions as follows:

| **Jurisdiction** | **Years** |
|---|---|
| Federal | 2018–2021 |
| Illinois | 2017–2021 |
| Michigan | 2017–2021 |
| Minnesota | 2017–2021 |
| Wisconsin | 2017–2021 |

## 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, 2021 | | | |
|---|---|---|---|---|
| *(in millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Derivative assets** | | | | |
| Natural gas contracts | **$ 46.4** | **$ 18.2** | **$ —** | **$ 64.6** |
| FTRs | **—** | **—** | **2.4** | **2.4** |
| Coal contracts | **—** | **53.0** | **—** | **53.0** |
| **Total derivative assets** | **$ 46.4** | **$ 71.2** | **$ 2.4** | **$ 120.0** |
| | | | | |
| Investments held in rabbi trust | **$ 79.6** | **$ —** | **$ —** | **$ 79.6** |
| | | | | |
| **Derivative liabilities** | | | | |
| Natural gas contracts | **$ 8.4** | **$ 6.7** | **$ —** | **$ 15.1** |

| (in millions) | December 31, 2020<br>Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Derivative assets** | | | | |
| Natural gas contracts | $ 11.7 | $ 2.0 | $ — | $ 13.7 |
| FTRs | — | — | 2.4 | 2.4 |
| Coal contracts | — | 1.8 | — | 1.8 |
| **Total derivative assets** | $ 11.7 | $ 3.8 | $ 2.4 | $ 17.9 |
| | | | | |
| Investments held in rabbi trust | $ 79.6 | $ — | $ — | $ 79.6 |
| | | | | |
| **Derivative liabilities** | | | | |
| Natural gas contracts | $ 7.7 | $ 6.4 | $ — | $ 14.1 |
| Coal contracts | — | 1.2 | — | 1.2 |
| Interest rate swaps | — | 6.8 | — | 6.8 |
| **Total derivative liabilities** | $ 7.7 | $ 14.4 | $ — | $ 22.1 |

The derivative assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices and interest rates. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets.

We hold investments in the Integrys rabbi trust. These investments are restricted as they can only be withdrawn from the trust 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. For the years ended December 31, 2021, 2020, and 2019, the net unrealized gains included in earnings related to the investments held at the end of the period were $16.0 million, $6.3 million, and $18.7 million, respectively.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy at December 31:

| *(in millions)* | **2021** | **2020** | **2019** |
|---|---|---|---|
| Balance at the beginning of the period | **$ 2.4** | $ 3.1 | $ 7.4 |
| Purchases | **6.1** | 7.6 | 12.8 |
| Settlements | **(6.1)** | (8.3) | (17.1) |
| **Balance at the end of the period** | **$ 2.4** | $ 2.4 | $ 3.1 |

## 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:

| *(in millions)* | **2021**<br>**Carrying Amount** | **Fair Value** | **2020**<br>**Carrying Amount** | **Fair Value** |
|---|---|---|---|---|
| Preferred stock of subsidiary | **$ 30.4** | **$ 30.3** | $ 30.4 | $ 32.3 |
| Long-term debt, including current portion [1] | **13,563.4** | **14,819.4** | 12,450.5 | 14,343.2 |

[1] The carrying amount of long-term debt excludes finance lease obligations of $129.7 million and $63.4 million at December 31, 2021 and 2020, respectively.

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

None of our derivatives are designated as hedging instruments, with the exception of interest rate swaps, which were designated as cash flow hedges. 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.

| | December 31, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| *(in millions)* | Derivative Assets | Derivative Liabilities | Derivative Assets | Derivative Liabilities |
| **Current** | | | | |
| Natural gas contracts | **$ 60.6** | **$ 14.0** | $ 13.0 | $ 12.9 |
| FTRs | **2.4** | **—** | 2.4 | — |
| Coal contracts | **44.0** | **—** | 1.6 | 0.8 |
| Interest rate swaps | **—** | **—** | — | 6.8 |
| **Total current** | **107.0** | **14.0** | 17.0 | 20.5 |
| | | | | |
| **Long-term** | | | | |
| Natural gas contracts | **4.0** | **1.1** | 0.7 | 1.2 |
| Coal contracts | **9.0** | **—** | 0.2 | 0.4 |
| **Total long-term** | **13.0** | **1.1** | 0.9 | 1.6 |
| **Total** | **$ 120.0** | **$ 15.1** | $ 17.9 | $ 22.1 |

Realized gains (losses) on derivatives not designated as hedging instruments are primarily recorded in cost of sales on the income statements. Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

| | December 31, 2021 | | December 31, 2020 | | December 31, 2019 | |
|---|---|---|---|---|---|---|
| *(in millions)* | Volumes | Gains | Volumes | Gains (Losses) | Volumes | Gains (Losses) |
| Natural gas contracts | **197.6 Dth** | **$ 136.5** | 188.6 Dth | $ (54.1) | 183.9 Dth | $ (27.1) |
| FTRs | **28.2 MWh** | **17.7** | 29.8 MWh | 4.1 | 31.2 MWh | 16.3 |
| **Total** | | **$ 154.2** | | $ (50.0) | | $ (10.8) |

At December 31, 2021 and 2020, we had posted cash collateral of $13.9 million and $18.9 million, respectively. We had also received cash collateral of $13.2 million at December 31, 2021.

The following table shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on our balance sheets:

| | December 31, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| *(in millions)* | Derivative Assets | Derivative Liabilities | Derivative Assets | Derivative Liabilities |
| Gross amount recognized on the balance sheet | **$ 120.0** | **$ 15.1** | $ 17.9 | $ 22.1 |
| Gross amount not offset on the balance sheet | **(15.2)** (1) | **(9.2)** (2) | (6.9) | (7.7) (3) |
| **Net amount** | **$ 104.8** | **$ 5.9** | $ 11.0 | $ 14.4 |

(1) Includes cash collateral received of $6.4 million.

(2) Includes cash collateral posted of $0.4 million.

(3) Includes cash collateral posted of $0.8 million.

### Cash Flow Hedges

Until their expiration on November 15, 2021, we had two interest rate swaps with a combined notional value of $250.0 million to hedge the variable interest rate risk associated with our 2007 Junior Notes. The swaps provided a fixed interest rate of 4.9765% on $250.0 million of the $500.0 million of outstanding 2007 Junior Notes. As these swaps qualified for cash flow hedge accounting treatment, the related gains and losses were deferred in accumulated other comprehensive loss and were amortized to interest expense as interest was accrued on the 2007 Junior Notes.

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 table below shows the amounts related to these cash flow hedges recorded in other comprehensive income (loss) and in earnings, along with our total interest expense on the income statements, for the years ended December 31:

| *(in millions)* | **2021** | 2020 | 2019 |
|---|---|---|---|
| Derivative gain (loss) recognized in other comprehensive income / loss | **$ 0.8** | $ (5.9) | $ (4.8) |
| Net derivative gain (loss) reclassified from accumulated other comprehensive loss to interest expense | **(1.3)** | (2.1) | 1.1 |
| Total interest expense line item on the income statements | **471.1** | 493.7 | 501.5 |

We estimate that during the next twelve months $0.4 million will be reclassified from accumulated other comprehensive loss as a reduction to interest expense.

## NOTE 19—GUARANTEES

The following table shows our outstanding guarantees:

| | | Expiration | | |
|---|---|---|---|---|
| *(in millions)* | **Total Amounts Committed at December 31, 2021** | Less Than 1 Year | 1 to 3 Years | Over 3 Years |
| Standby letters of credit [1] | **$ 75.2** | $ 2.5 | $ 0.2 | $ 72.5 |
| Surety bonds [2] | **12.8** | 12.8 | — | — |
| Other guarantees [3] | **9.4** | — | — | 9.4 |
| **Total guarantees** | **$ 97.4** | $ 15.3 | $ 0.2 | $ 81.9 |

[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 workers compensation self-insurance programs and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

[3] Consists of $9.4 million 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, former Wisconsin Energy Corporation employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. 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)* | 2021 | 2020 | 2021 | 2020 |
| **Change in benefit obligation** | | | | |
| Obligation at January 1 | **$ 3,346.4** | $ 3,123.7 | **$ 556.1** | $ 558.6 |
| Service cost | **54.3** | 50.1 | **15.7** | 15.2 |
| Interest cost | **87.5** | 102.8 | **14.5** | 18.6 |
| Participant contributions | **—** | — | **12.5** | 13.3 |
| Plan amendments | **—** | — | **(3.9)** | (5.0) |
| Actuarial loss (gain) | **(101.3)** | 311.6 | **(20.3)** | (1.4) |
| Benefit payments | **(250.3)** | (241.8) | **(47.5)** | (46.1) |
| Federal subsidy on benefits paid | N/A | N/A | **1.2** | 1.3 |
| Transfer | **—** | — | **1.9** | 1.6 |
| **Obligation at December 31** | **$ 3,136.6** | $ 3,346.4 | **$ 530.2** | $ 556.1 |
| | | | | |
| **Change in fair value of plan assets** | | | | |
| Fair value at January 1 | **$ 3,225.0** | $ 3,007.0 | **$ 951.4** | $ 879.6 |
| Actual return on plan assets | **291.8** | 348.1 | **79.9** | 103.1 |
| Employer contributions | **62.4** | 111.7 | **3.9** | 1.5 |
| Participant contributions | **—** | — | **12.5** | 13.3 |
| Benefit payments | **(250.3)** | (241.8) | **(47.5)** | (46.1) |
| **Fair value at December 31** | **$ 3,328.9** | $ 3,225.0 | **$ 1,000.2** | $ 951.4 |
| **Funded status at December 31** | **$ 192.3** | $ (121.4) | **$ 470.0** | $ 395.3 |

In 2021 we had actuarial gains related to our pension benefit obligations of $101.3 million and actuarial losses in 2020 of $311.6 million, both of which were primarily driven by changes in our discount rates. The discount rate for our pension benefits was 2.96%, 2.67%, and 3.41%, in 2021, 2020, and 2019, respectively.

The actuarial gains related to our OPEB benefit obligations were not significant for 2021 or 2020.

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)* | 2021 | 2020 | 2021 | 2020 |
| Pension and OPEB assets | **$ 389.0** | $ 182.9 | **$ 492.3** | $ 418.0 |
| Pension and OPEB obligations | **196.7** | 304.3 | **22.3** | 22.7 |
| **Total net (liabilities) assets** | **$ 192.3** | $ (121.4) | **$ 470.0** | $ 395.3 |

The accumulated benefit obligation for all defined benefit pension plans was $3,010.5 million and $3,194.3 million as of December 31, 2021 and 2020, 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)* | 2021 | 2020 |
|---|---|---|
| Accumulated benefit obligation | **$ 372.4** | $ 1,555.5 |
| Fair value of plan assets | **186.3** | 1,298.3 |

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)* | 2021 | 2020 |
|---|---|---|
| Projected benefit obligation | **$ 383.0** | $ 2,034.1 |
| Fair value of plan assets | **186.3** | 1,729.8 |

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)* | 2021 | 2020 |
|---|---|---|
| Accumulated benefit obligation | **$ 25.1** | $ 25.7 |
| Fair value of plan assets | **2.8** | 3.0 |

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)* | 2021 | 2020 | 2021 | 2020 |
| **Pre-tax accumulated other comprehensive income (loss)** [1] | | | | |
| Net actuarial loss (gain) | **$ 7.5** | $ 10.4 | **$ (1.4)** | $ (1.4) |
| Prior service credits | **—** | — | **(0.1)** | (0.1) |
| **Total** | **$ 7.5** | $ 10.4 | **$ (1.5)** | $ (1.5) |
| | | | | |
| **Net regulatory assets (liabilities)** [2] | | | | |
| Net actuarial loss (gain) | **$ 798.6** | $ 1,101.2 | **$ (300.1)** | $ (288.7) |
| Prior service costs (credits) | **(0.5)** | 1.1 | **(60.3)** | (78.6) |
| **Total** | **$ 798.1** | $ 1,102.3 | **$ (360.4)** | $ (367.3) |

[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)* | 2021 | 2020 | 2019 | 2021 | 2020 | 2019 |
| Service cost | **$ 54.3** | $ 50.1 | $ 47.0 | **$ 15.7** | $ 15.2 | $ 16.3 |
| Interest cost | **87.5** | 102.8 | 120.4 | **14.5** | 18.6 | 25.7 |
| Expected return on plan assets | **(200.9)** | (190.3) | (193.3) | **(66.0)** | (60.3) | (54.7) |
| Plan settlement | **3.9** | 17.9 | 11.5 | **—** | — | — |
| Plan curtailment | **—** | — | — | **(6.4)** | — | — |
| Amortization of prior service cost (credit) | **1.6** | 1.6 | 2.2 | **(15.9)** | (15.0) | (15.4) |
| Amortization of net actuarial loss (gain) | **109.4** | 102.6 | 77.3 | **(24.4)** | (22.4) | (6.6) |
| **Net periodic benefit cost (credit)** | **$ 55.8** | $ 84.7 | $ 65.1 | **$ (82.5)** | $ (63.9) | $ (34.7) |

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 | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Discount rate | **2.96%** | 2.67% | **2.92%** | 2.60% |
| Rate of compensation increase | **4.00%** | 4.00% | **N/A** | N/A |
| Interest credit rate | **3.73%** | 3.69% | **N/A** | N/A |
| Assumed medical cost trend rate (Pre 65) | **N/A** | N/A | **5.70%** | 5.85% |
| 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 | **2028** | 2028 |
| Assumed medical cost trend rate (Post 65) | **N/A** | N/A | **5.67%** | 5.80% |
| 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 | **2028** | 2028 |

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 | | |
|---|---|---|---|
| | **2021** | **2020** | **2019** |
| Discount rate | **2.71%** | 3.34% | 4.21% |
| Expected return on plan assets | **6.88%** | 6.87% | 7.12% |
| Rate of compensation increase | **4.00%** | 4.00% | 3.66% |
| Interest credit rate | **3.71%** | 3.70% | 3.72% |

| | OPEB Benefits | | |
|---|---|---|---|
| | **2021** | **2020** | **2019** |
| Discount rate | **2.66%** | 3.39% | 4.27% |
| Expected return on plan assets | **7.00%** | 7.00% | 7.25% |
| Assumed medical cost trend rate (Pre 65) | **5.85%** | 6.00% | 6.25% |
| Ultimate trend rate (Pre 65) | **5.00%** | 5.00% | 5.00% |
| Year ultimate trend rate is reached (Pre 65) | **2028** | 2028 | 2024 |
| Assumed medical cost trend rate (Post 65) | **5.80%** | 5.91% | 6.01% |
| Ultimate trend rate (Post 65) | **5.00%** | 5.00% | 5.00% |
| Year ultimate trend rate is reached (Post 65) | **2028** | 2028 | 2028 |

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 fund. For 2022, the expected return on assets assumption is 6.88% for the pension plans and 7.00% 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 legacy Wisconsin Energy Corporation pension trust target asset allocations are 35% equity investments, 55% fixed income investments, and 10% private equity and real estate investments. The legacy Integrys pension trust target asset allocations are 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. The legacy Wisconsin

Energy Corporation OPEB trust target asset allocations are 50% equity investments and 50% fixed income investments. The two largest legacy OPEB trusts for Integrys have the same target asset allocations of 45% equity investments and 55% fixed income 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, 2021 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 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 | $ 417.1 | $ — | $ — | $ 417.1 | $ 135.4 | $ — | $ — | $ 135.4 |
| International equity | 313.7 | — | — | 313.7 | 109.1 | — | — | 109.1 |
| Fixed income securities: [1] | | | | | | | | |
| United States bonds | — | 1,068.7 | — | 1,068.7 | 165.0 | 192.3 | — | 357.3 |
| International bonds | — | 118.5 | — | 118.5 | — | 15.6 | — | 15.6 |
| | 730.8 | 1,187.2 | — | 1,918.0 | 409.5 | 207.9 | — | 617.4 |
| Investments measured at net asset value | | | | 1,410.9 | | | | 382.8 |
| **Total** | $ 730.8 | $ 1,187.2 | $ — | $ 3,328.9 | $ 409.5 | $ 207.9 | $ — | $ 1,000.2 |

[1] This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

| | December 31, 2020 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 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 | $ 439.2 | $ — | $ — | $ 439.2 | $ 141.4 | $ — | $ — | $ 141.4 |
| International equity | 345.1 | — | — | 345.1 | 120.9 | — | — | 120.9 |
| Fixed income securities: [1] | | | | | | | | |
| United States bonds | — | 1,056.4 | — | 1,056.4 | 143.0 | 179.9 | — | 322.9 |
| International bonds | — | 114.3 | — | 114.3 | — | 12.0 | — | 12.0 |
| | 784.3 | 1,170.7 | — | 1,955.0 | 405.3 | 191.9 | — | 597.2 |
| Investments measured at net asset value | | | | 1,270.0 | | | | 354.2 |
| **Total** | $ 784.3 | $ 1,170.7 | $ — | $ 3,225.0 | $ 405.3 | $ 191.9 | $ — | $ 951.4 |

[1] This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

## Cash Flows

We expect to contribute $11.2 million to the pension plans and $2.5 million to the OPEB plans in 2022, 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 |
|---|---|---|
| 2022 | $ 231.6 | $ 35.0 |
| 2023 | 228.8 | 35.1 |
| 2024 | 222.8 | 34.9 |
| 2025 | 216.7 | 34.7 |
| 2026 | 219.9 | 34.6 |
| 2027-2031 | 946.2 | 170.4 |

## 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 an employer retirement contribution, in which amounts are contributed to the employee's savings plan account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $51.8 million, $49.7 million, and $50.9 million in 2021, 2020, and 2019, 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 eleven-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:

| | 2021 | | |
|---|---|---|---|
| *(in millions)* | ATC | ATC Holdco | Total |
| Balance at January 1 | **$ 1,733.5** | **$ 30.8** | **$ 1,764.3** |
| Add: Earnings (loss) from equity method investment | **166.4** | **(8.3)** | **158.1** |
| Less: Distributions | **133.0** | **—** | **133.0** |
| **Balance at December 31** | **$ 1,766.9** | **$ 22.5** | **$ 1,789.4** |

| | 2020 | | |
|---|---|---|---|
| *(in millions)* | ATC | ATC Holdco | Total |
| Balance at January 1 | $ 1,684.7 | $ 36.1 | $ 1,720.8 |
| Add: Earnings from equity method investment | 174.3 | 1.5 | 175.8 |
| Add: Capital contributions | 21.2 | — | 21.2 |
| Less: Distributions | 146.7 | — | 146.7 |
| Less: Return of capital | — | 6.8 | 6.8 |
| **Balance at December 31** | $ 1,733.5 | $ 30.8 | $ 1,764.3 |

| | 2019 | | |
|---|---|---|---|
| *(in millions)* | ATC | ATC Holdco | Total |
| Balance at January 1 | $ 1,625.3 | $ 40.0 | $ 1,665.3 |
| Add: Earnings (loss) from equity method investment | 132.8 | (5.2) | 127.6 |
| Add: Capital contributions | 51.3 | 1.3 | 52.6 |
| Less: Distributions | 124.7 | — | 124.7 |
| **Balance at December 31** | $ 1,684.7 | $ 36.1 | $ 1,720.8 |

In November 2019 and May 2020, the FERC issued orders that addressed complaints related to ATC's allowed ROE. Due to the various outstanding petitions filed related to these orders, our financials continue to include a $39.1 million liability for potential future refunds that ATC may be required to provide, reducing our equity earnings from ATC. This liability reflects a 10.52% ROE for all periods covered by the complaints.

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)* | **2021** | 2020 | 2019 |
|---|---|---|---|
| Charges to ATC for services and construction | **$ 22.9** | $ 27.5 | $ 25.9 |
| Charges from ATC for network transmission services | **361.0** | 350.5 | 348.1 |
| Net refund from ATC related to FERC ROE orders | **7.3** | 10.7 | — |

As of December 31, 2021 and 2020, our balance sheets included the following receivables and payables for services provided to or received from ATC:

| *(in millions)* | **2021** | 2020 |
|---|---|---|
| Accounts receivable for services provided to ATC | **$ 2.0** | $ 3.7 |
| Accounts payable for services received from ATC | **30.2** | 29.3 |
| Amounts due from ATC for transmission infrastructure upgrades [(1)] | **13.0** | 4.6 |

(1) The transmission infrastructure upgrades were primarily related to WE's and WPS's construction of their new solar projects, Badger Hollow II and Badger Hollow I, respectively.

Summarized financial data for ATC is included in the tables below:

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | 2020 | 2019 |
| **Income statement data** | | | |
| Operating revenues | **$ 754.8** | $ 758.1 | $ 744.4 |
| Operating expenses | **376.2** | 372.5 | 373.5 |
| Other expense, net | **113.9** | 110.8 | 110.5 |
| **Net income** | **$ 264.7** | $ 274.8 | $ 260.4 |

| *(in millions)* | **December 31, 2021** | **December 31, 2020** |
|---|---|---|
| **Balance sheet data** | | |
| Current assets | **$ 89.8** | $ 92.7 |
| Noncurrent assets | **5,628.1** | 5,400.6 |
| **Total assets** | **$ 5,717.9** | $ 5,493.3 |
| | | |
| Current liabilities | **$ 436.9** | $ 310.8 |
| Long-term debt | **2,513.0** | 2,512.2 |
| Other noncurrent liabilities | **422.0** | 378.2 |
| Members' equity | **2,346.0** | 2,292.1 |
| **Total liabilities and members' equity** | **$ 5,717.9** | $ 5,493.3 |

## NOTE 22—SEGMENT INFORMATION

We use net income attributed to common shareholders to measure segment profitability and to allocate resources to our businesses. At December 31, 2021, we reported six segments, which are described below.

- 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 and non-utility operations of MERC and MGU.

- 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.

- 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 holds our ownership interests in the following wind generating facilities:
    - 90% ownership interest in Bishop Hill III, located in Henry County, Illinois,
    - 80% ownership interest in Coyote Ridge, located in Brookings County, South Dakota,
    - 90% ownership interest in Upstream, located in Antelope County, Nebraska,
    - 90% ownership interest in Blooming Grove, located in McLean County, Illinois,
    - 85% ownership interest in Tatanka Ridge, located in Deuel County, South Dakota, and
    - 90% ownership interest in Jayhawk, located in Bourbon and Crawford counties, Kansas.

  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, WBS, and also included the operations of PDL prior to the sale of its remaining solar facilities in the fourth quarter of 2020. See Note 3, Dispositions, for more information on the sale of these solar facilities.

All of our operations and assets are located within the United States. The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2021, 2020, and 2019.

| | **Utility Operations** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2021 *(in millions)*** | **Wisconsin** | **Illinois** | **Other States** | **Total Utility Operations** | **Electric Transmission** | **Non-Utility Energy Infrastructure** | **Corporate and Other** | **Reconciling Eliminations** | **WEC Energy Group Consolidated** |
| External revenues | $ 6,037.0 | $ 1,672.8 | $ 519.0 | $ 8,228.8 | $ — | $ 86.7 | $ 0.5 | $ — | $ 8,316.0 |
| Intersegment revenues | — | — | — | — | — | 452.8 | — | (452.8) | — |
| Other operation and maintenance | 1,455.2 | 433.5 | 90.4 | 1,979.1 | — | 43.1 | (7.5) | (9.2) | 2,005.5 |
| Depreciation and amortization | 726.9 | 218.1 | 38.1 | 983.1 | — | 125.3 | 25.9 | (60.0) | 1,074.3 |
| Equity in earnings of transmission affiliates | — | — | — | — | 158.1 | — | — | — | 158.1 |
| Interest expense | 555.6 | 66.6 | 6.2 | 628.4 | 19.4 | 71.0 | 92.8 | (340.5) | 471.1 |
| Loss on debt extinguishment | — | — | — | — | — | — | 36.3 | — | 36.3 |
| Income tax expense (benefit) | 119.9 | 79.3 | 11.5 | 210.7 | 32.3 | 3.1 | (45.8) | — | 200.3 |
| Net income (loss) | 707.7 | 223.0 | 35.8 | 966.5 | 106.3 | 276.2 | (50.5) | — | 1,298.5 |
| Net income (loss) attributed to common shareholders | 706.5 | 223.0 | 35.8 | 965.3 | 106.3 | 279.2 | (50.5) | — | 1,300.3 |
| Capital expenditures and asset acquisitions | 1,389.7 | 533.7 | 95.9 | 2,019.3 | — | 335.3 | 18.1 | — | 2,372.7 |
| Total assets [1] | 25,687.9 | 7,853.4 | 1,506.1 | 35,047.4 | 1,792.7 | 4,627.7 | 785.3 | (3,264.6) | 38,988.5 |

[1] Total assets at December 31, 2021 reflect an elimination of $1,729.9 million for all lease activity between We Power and WE.

| 2020 *(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 | $ 5,473.5 | $ 1,321.9 | $ 384.1 | $ 7,179.5 | $ — | $ 60.0 | $ 2.2 | $ — | $ 7,241.7 |
| Intersegment revenues | — | — | — | — | — | 448.5 | — | (448.5) | — |
| Other operation and maintenance | 1,476.7 | 435.4 | 87.0 | 1,999.1 | — | 24.9 | 17.4 | (9.2) | 2,032.2 |
| Depreciation and amortization | 674.5 | 196.7 | 33.5 | 904.7 | — | 98.9 | 25.1 | (52.8) | 975.9 |
| Equity in earnings of transmission affiliates | — | — | — | — | 175.8 | — | — | — | 175.8 |
| Interest expense | 561.3 | 63.5 | 10.2 | 635.0 | 19.4 | 60.8 | 124.0 | (345.5) | 493.7 |
| Loss on debt extinguishment | — | — | — | — | — | — | 38.4 | — | 38.4 |
| Income tax expense (benefit) | 132.7 | 66.1 | 13.1 | 211.9 | 43.7 | 44.7 | (72.4) | — | 227.9 |
| Net income (loss) | 691.6 | 203.5 | 39.0 | 934.1 | 112.6 | 261.1 | (106.4) | — | 1,201.4 |
| Net income (loss) attributed to common shareholders | 690.4 | 203.5 | 39.0 | 932.9 | 112.6 | 260.8 | (106.4) | — | 1,199.9 |
| Capital expenditures and asset acquisitions | 1,382.4 | 652.7 | 144.3 | 2,179.4 | — | 661.8 | 33.1 | — | 2,874.3 |
| Total assets [1] | 24,599.2 | 7,471.8 | 1,336.2 | 33,407.2 | 1,764.7 | 4,455.2 | 762.2 | (3,361.2) | 37,028.1 |

[1] Total assets at December 31, 2020 reflect an elimination of $1,824.5 million for all lease activity between We Power and WE.

| 2019 *(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 | $ 5,647.1 | $ 1,357.1 | $ 426.0 | $ 7,430.2 | $ — | $ 88.5 | $ 4.4 | $ — | $ 7,523.1 |
| Intersegment revenues | — | — | — | — | — | 407.4 | — | (407.4) | — |
| Other operation and maintenance | 1,591.3 | 461.1 | 98.5 | 2,150.9 | — | 19.7 | 14.0 | 0.2 | 2,184.8 |
| Depreciation and amortization | 617.0 | 181.3 | 27.5 | 825.8 | — | 92.0 | 24.3 | (15.8) | 926.3 |
| Equity in earnings of transmission affiliates | — | — | — | — | 127.6 | — | — | — | 127.6 |
| Interest expense | 572.0 | 59.0 | 8.5 | 639.5 | 13.1 | 62.1 | 140.9 | (354.1) | 501.5 |
| Income tax expense (benefit) | 35.2 | 60.2 | 13.6 | 109.0 | 27.1 | 59.9 | (71.0) | — | 125.0 |
| Net income (loss) | 651.1 | 170.3 | 43.2 | 864.6 | 87.4 | 245.5 | (62.8) | — | 1,134.7 |
| Net income (loss) attributed to common shareholders | 649.9 | 170.3 | 43.2 | 863.4 | 87.4 | 246.0 | (62.8) | — | 1,134.0 |
| Capital expenditures and asset acquisitions | 1,378.6 | 624.9 | 109.1 | 2,112.6 | — | 389.9 | 26.5 | — | 2,529.0 |
| Total assets [1] | 23,934.8 | 6,932.5 | 1,237.8 | 32,105.1 | 1,723.1 | 3,654.1 | 814.0 | (3,344.5) | 34,951.8 |

[1] Total assets at December 31, 2019 reflect an elimination of $1,896.7 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 source of funds to satisfy the debt obligation. The bondholders have no recourse to WE or any of WE's affiliates. See Note 14, Long-Term Debt, for more information on the ETBs.

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 an indenture trustee of WEPCo Environmental Trust.

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 sheet.

| ***(in millions)*** | **December 31, 2021** |
|---|---|
| **Assets** | |
| Other current assets (restricted cash) | **$ 2.4** |
| Regulatory assets | **100.7** |
| Other long-term assets (restricted cash) | **0.6** |
| | |
| **Liabilities** | |
| Current portion of long-term debt | **8.8** |
| Other current liabilities (accrued interest) | **0.1** |
| Long-term debt | **102.7** |

### 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, 2021 and 2020, our equity investment in ATC was $1,766.9 million and $1,733.5 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, 2021 and 2020, our equity investment in ATC Holdco was $22.5 million and $30.8 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.

### Power Purchase Commitment

WE has a PPA with LSP-Whitewater Limited Partnership that represents a variable interest. This agreement is for 236.5 MWs of firm capacity from a natural gas-fired cogeneration facility, and we account for it as a finance lease. The agreement expires on May 31, 2022 and includes no minimum energy requirements over the remaining term. We have examined the risks of the entity, including operations, maintenance, dispatch, financing, fuel costs, and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity, and there is no residual guarantee associated with the PPA.

In November 2021, WE entered into a tolling agreement with LSP-Whitewater Limited Partnership that commences on June 1, 2022 upon the expiration of the PPA. Concurrent with the execution of the tolling agreement, WE and WPS also entered into an agreement to purchase the natural gas-fired cogeneration facility for $72.7 million. This purchase agreement is subject to regulatory approval by the PSCW, which is expected by the end of 2022. The tolling agreement extends until the earlier of the closing of the asset purchase or December 31, 2022. Since the terms of the tolling agreement are substantially similar to the terms of the PPA, we have determined that we are still not the primary beneficiary of the entity, and we will continue to account for the PPA and tolling agreement as a finance lease. See Note 15, Leases, for more information.

We have $6.4 million of required capacity payments over the remaining term of the PPA and tolling agreement. We believe that the required capacity payments under the agreements will continue to be recoverable in rates, and our maximum exposure to loss is limited to these capacity payments.

## 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 wind 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 wind generating facilities.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2021, including those of our subsidiaries.

| (in millions) | Date Contracts Extend Through | Total Amounts Committed | Payments Due By Period 2022 | 2023 | 2024 | 2025 | 2026 | Later Years |
|---|---|---|---|---|---|---|---|---|
| Electric utility: | | | | | | | | |
| Nuclear | 2033 | $ 7,342.8 | $ 531.2 | $ 563.0 | $ 596.8 | $ 632.6 | $ 677.9 | $ 4,341.3 |
| Coal supply and transportation | 2025 | 821.8 | 260.9 | 213.3 | 180.0 | 167.6 | — | — |
| Purchased power | 2051 | 316.5 | 65.5 | 60.7 | 53.2 | 46.9 | 43.8 | 46.4 |
| Natural gas utility: | | | | | | | | |
| Supply and transportation | 2048 | 1,704.4 | 349.4 | 264.7 | 201.0 | 128.9 | 109.2 | 651.2 |
| Non-utility energy infrastructure: | | | | | | | | |
| Purchased power | 2051 | 396.3 | 20.6 | 22.5 | 20.6 | 21.0 | 21.4 | 290.2 |
| Natural gas storage and transportation | 2048 | 6.9 | 5.1 | 0.8 | — | — | 0.1 | 0.9 |
| **Total** | | $ 10,588.7 | $ 1,232.7 | $ 1,125.0 | $ 1,051.6 | $ 997.0 | $ 852.4 | $ 5,330.0 |

## 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, 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;
- 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 utility 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 reporting of GHG emissions to comply with federal clean air rules.

### *Air Quality*

#### 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. In December 2020, the EPA completed its 5-year review of the ozone standard and issued a final decision to retain, without any changes, the existing 2015 standard. Under Executive Order 13990, the Biden Administration ordered that all agencies review existing regulations, orders, guidance documents, policies, and similar actions promulgated, issued, or adopted between January 20, 2017 and January 20, 2021. In October 2021, the EPA announced that it will reconsider the December 2020 decision to retain the 2015 ozone standards with no changes and that it is targeting the end of 2023 to complete this reconsideration.

The EPA issued final nonattainment area designations for the 2015 ozone standard in April 2018. The following counties within our Wisconsin service territories were designated as partial nonattainment: Door, Kenosha, Sheboygan, Manitowoc, and Northern Milwaukee/Ozaukee. This re-designation was challenged in the D.C. Circuit Court of Appeals in *Clean Wisconsin et al. v. U.S. Environmental Protection Agency.* A decision was issued in July 2020 remanding the rule to the EPA for further evaluation. As a result of the July 2020 remand, in June 2021, the EPA published its final action to revise the boundaries for 13 counties associated with six nonattainment areas, including several in Illinois and Wisconsin. Under the new designations, all of Milwaukee and Ozaukee counties are now listed as nonattainment and portions of Racine, Waukesha, and Washington counties have been added to the nonattainment area. Additionally, the Chicago, Illinois, Indiana, and Wisconsin nonattainment area now includes an expanded portion of Kenosha county, and the partial nonattainment areas of Sheboygan, Door, and Manitowoc counties have also been expanded. Preliminary 2019-2021 monitoring data indicates that the Milwaukee, Sheboygan, and Chicago nonattainment areas will likely be adjusted to "moderate" nonattainment for the 2015 standard.

In February 2021, the WDNR proposed draft revisions to the Wisconsin Administrative Code to adopt the 2015 ozone standard and incorporate by reference the federal air pollution monitoring requirements related to the NAAQS. The Natural Resources Board adopted the rule as proposed during their June 2021 meeting and the rule is now in legislative review. We believe that we are well positioned to meet the requirements associated with the 2015 ozone standard and do not expect to incur significant costs to comply with associated state or federal rules.

***Particulate Matter***

In addition to the 2015 ozone standard, in December 2020, the EPA completed its 5-year review of the 2012 standard for particulate matter, including fine particulate matter. The EPA determined that no revisions were necessary to the current standard. This determination was also subject to review under Executive Order 13990 and in June 2021, the EPA announced it would reconsider the December 2020 decision. Under the Biden Administration's policy review, the EPA concluded that the scientific evidence and information from the December 2020 determination supports revising the level of the annual standard for the particulate matter NAAQS to below the current level of 12 micrograms per cubic meter, while retaining the 24-hour standard. A proposed rule-making is expected in summer 2022, and a final rule is expected in spring 2023. All counties within our service territories are in attainment with the current 2012 standards. If the EPA lowers the standard to 10 or 11 micrograms per cubic meter, our service territories should remain in attainment. If the EPA lowers it below 10 micrograms per cubic meter, there could be some non-attainment areas that may affect permitting of some smaller ancillary equipment located at our facilities.

**Climate Change**

The ACE rule, effective since September 2019, was vacated by the D.C. Circuit Court of Appeals in January 2021. The ACE rule replaced the Clean Power Plan and provided existing coal-fired generating units with standards for achieving GHG emission reductions. In a memorandum issued to the EPA regional administrators in February 2021, the EPA stated that the D.C. Circuit Court decision meant that no existing rule regulates GHG emissions from electric generating units. The EPA is currently reviewing its options for such regulations and has signaled that a draft rule may be released in 2022 at the earliest. In October 2021, the Supreme Court agreed to review the D.C. Circuit Court's ruling vacating the EPA's ACE rule. The Supreme Court is expected to review a number of issues regarding the scope of the EPA's regulatory authority to utilize Section 111(d) of the CAA to address $CO_2$ emissions. Arguments are expected to take place in early 2022 with a decision expected by the summer of 2022.

In January 2021, the EPA finalized a rule to revise the New Source Performance Standards for GHG emissions from new, modified, and reconstructed fossil-fueled power plants. The rule became effective in March 2021; however, it was vacated by the D.C. Circuit Court of Appeals in April 2021. The EPA has signaled that a rule replacement is expected by June 2022. We continue to move forward on the ESG Progress Plan, which is heavily focused on reducing GHG emissions.

Our ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fueled generation. We have already retired more than 1,800 MW of coal-fired generation since the beginning of 2018. Through our ESG Progress Plan, we expect to retire approximately 1,600 MW of additional fossil-fueled generation by 2025, which includes the planned retirements in 2023-2024 of OCPP Units 5-8 and the jointly-owned Columbia Units 1-2. In May 2021, we announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by 2025 and by 80% by 2030, both from a 2005 baseline. We expect to achieve these goals by making operating refinements, retiring less efficient generating units, and executing our capital plan. Over the longer term, the target for our generation fleet is net-zero $CO_2$ emissions by 2050.

We also continue to reduce methane emissions by improving our natural gas distribution system. We set a target across our natural gas distribution operations to achieve net-zero methane emissions by 2030. We plan to achieve our net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of RNG throughout our utility systems.

We are required to report our $CO_2$ equivalent emissions from the electric generating facilities we operate under the EPA Greenhouse Gases Reporting Program. Based upon our preliminary analysis of the data, we estimate that we will report $CO_2$ equivalent emissions of approximately 22.0 million metric tonnes to the EPA for 2021. The level of $CO_2$ and other GHG emissions varies from year to year and is dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report $CO_2$ equivalent emissions related to the natural gas that our natural gas utilities distribute and sell. Based upon our preliminary analysis of the data, we estimate that we will report $CO_2$ equivalent emissions of approximately 23.6 million metric tonnes to the EPA for 2021.

## *Water Quality*

**Clean Water Act Cooling Water Intake Structure Rule**

In August 2014, the EPA issued a final regulation under Section 316(b) of the Clean Water Act that requires the location, design, construction, and capacity of cooling water intake structures at existing power plants to reflect the BTA for minimizing adverse environmental impacts. The federal rule became effective in October 2014 and applies to all of our existing generating facilities with cooling water intake structures, except for the ERGS units, which were permitted under the rules governing new facilities. In 2016, the WDNR initiated a state rulemaking process to incorporate the federal Section 316(b) requirements into the Wisconsin Administrative Code. This new state rule, NR 111, became effective in June 2020, and the WDNR will apply it when establishing BTA requirements for cooling water intake structures at existing facilities. These BTA requirements are incorporated into Wisconsin Pollutant Discharge Elimination System permits for WE and WPS facilities.

We have received BTA determinations for OC 5 through OC 8 and VAPP. Although we currently believe that existing technology at the PWGS satisfies the BTA requirements, a final determination will not be made until the discharge permit is renewed for this facility, which is expected to be in the second quarter of 2022. We have received interim BTA determinations for Weston Units 2, 3, and 4. A final BTA decision for the Weston facility is expected during its next permit renewal in late 2023.

As a result of past capital investments completed to address Section 316(b) compliance at WE and WPS, we believe our fleet overall is well positioned to continue to meet this regulation and do not expect to incur significant additional compliance costs.

**Steam Electric Effluent Limitation Guidelines**

The EPA's final 2015 ELG rule took effect in January 2016 and was modified in 2020 to revise the treatment technology requirements related to BATW and wet FGD wastewaters at existing facilities. This rule created new requirements for several types of power plant wastewaters. The two new requirements that affect WE and WPS relate to discharge limits for BATW and wet FGD wastewater. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. There will, however, need to be facility modifications to meet water permit requirements for the BATW systems at Weston Unit 3 (to be completed by December 2023) and OC 7 and OC 8 (completed and placed in-service in mid-2021). Wastewater treatment system modifications also will be required for wet FGD discharges and site wastewater from the OCPP and ERGS units. Based on engineering cost estimates, we expect that compliance with the ELG rule will require approximately $110 million in capital investment. In December 2021, the PSCW Division of Energy Regulation and Analysis issued a Certificate of Authority approving the ERGS FGD wastewater treatment system modification. The BATW modifications do not require PSCW approval prior to construction. All of these ELG required projects are either in-service or are on track for completion by the Wisconsin Pollutant Discharge Elimination System permit deadlines.

In July 2021, the EPA announced that it intends to initiate rulemaking to revise the ELG Rule as modified in 2020. The EPA has stated that the ELG Rule will continue to be implemented and enforced while the agency pursues this rulemaking process. The EPA plans to propose a revised rule in the fall of 2022.

**Waters of the United States**

In December 2021, the EPA and the United States Army Corps of Engineers together released a proposed rule to repeal the April 2020 Navigable Waters Protection Rule that defined WOTUS. The purpose of this proposed rule will be to restore regulations defining WOTUS that were in place prior to 2015 and to update certain provisions to be consistent with relevant Supreme Court decisions. The pre-2015 approach involves applying factors established through case law and agency precedents to determine whether a wetland or surface drainage feature is subject to federal jurisdiction. In January 2022, the Supreme Court granted certiorari in a case to evaluate the proper test for determining whether wetlands are WOTUS. At this point, our projects requiring federal permits are moving ahead, but we are monitoring to better understand potential future impacts.

### *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, some of which are in the EPA Superfund Alternative Approach Program. We are also working with various state jurisdictions in our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

In addition, we are coordinating the investigation and cleanup of some of these sites subject to the jurisdiction of the EPA under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

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)* | 2021 | 2020 |
|---|---|---|
| Regulatory assets | **$ 630.9** | $ 638.2 |
| Reserves for future environmental remediation | **532.6** | 532.9 |

### *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 parks, solar parks, 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, 2021. 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.

## 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.

### *Consent Decrees*

**Wisconsin Public Service Corporation – Weston and Pulliam Power Plants**

In November 2009, the EPA issued an NOV to WPS, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam power plants from 1994 to 2009. WPS entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Eastern District of Wisconsin in March 2013.

With the retirement of Pulliam Units 7 and 8 in October 2018, WPS completed the mitigation projects required by the Consent Decree and received a completeness letter from the EPA in October 2018. See Note 6, Regulatory Assets and Liabilities, for more information about the retirement. We are working with the EPA on a closeout process for the Consent Decree.

**Joint Ownership Power Plants – Columbia and Edgewater**

In December 2009, the EPA issued an NOV to Wisconsin Power and Light Company, the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric Company, WE (former co-owner of an Edgewater unit), and WPS. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, along with Wisconsin Power and Light Company, Madison Gas and Electric Company, and WE, entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Western District of Wisconsin in June 2013. As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, the Edgewater 4 generating unit was retired in September 2018. See Note 6, Regulatory Assets and Liabilities, for more information about the retirement. Wisconsin Power and Light Company has started the process to close out this Consent Decree.

## NOTE 25—SUPPLEMENTAL CASH FLOW INFORMATION

| | Year Ended December 31 | | |
|---|---|---|---|
| *(in millions)* | **2021** | **2020** | **2019** |
| Cash paid for interest, net of amount capitalized | **$ 473.8** | $ 492.9 | $ 485.9 |
| Cash paid (received) for income taxes, net | **33.8** | 27.9 | (24.9) |
| Significant non-cash investing and financing transactions: | | | |
| Accounts payable related to construction costs | **127.8** | 153.1 | 159.9 |
| Increase in receivable related to insurance proceeds | **41.7** | 2.7 | — |
| Non-cash capital contributions from noncontrolling interest | **1.5** | — | 21.0 |

The statements of cash flows include our activity related to cash, cash equivalents, and restricted cash. Our restricted cash primarily consists of the 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. All assets held within the rabbi trust are restricted as they can only be withdrawn from the trust to make qualifying benefit payments. Our restricted cash also consists of cash on deposit in financial institutions that is restricted to satisfy the requirements of certain debt agreements at WECI Wind Holding I and WEPCo Environmental Trust. The restricted cash we received when WECI acquired ownership interests in certain wind generation projects is included in our restricted cash as well. This cash is restricted as it can only be used to pay for any remaining costs associated with the construction of the wind generation facilities. See Note 2, Acquisitions, for more information on the acquisitions of these wind generation projects.

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)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Cash and cash equivalents | **$ 16.3** | $ 24.8 | $ 37.5 |
| Restricted cash included in other current assets | **19.6** | — | — |
| Restricted cash included in other long term assets | **51.6** | 47.8 | 44.8 |
| **Cash, cash equivalents, and restricted cash** | **$ 87.5** | $ 72.6 | $ 82.3 |

## NOTE 26—REGULATORY ENVIRONMENT

### Recovery of Natural Gas Costs

Due to the cold temperatures, wind, snow, and ice throughout the central part of the country during February 2021, the cost of gas purchased for our natural gas utility customers was temporarily driven significantly higher than our normal winter weather expectations. All of our utilities have regulatory mechanisms in place for recovering all prudently incurred gas costs.

On March 23, 2021, WE and WG requested approval from the PSCW to recover approximately $54 million and $24 million, respectively, of natural gas costs in excess of the benchmark set in their GCRMs. On March 30, 2021, the PSCW approved the requests and both WE and WG recovered these excess costs over a period of three months, beginning in April 2021. In March 2021, WPS also filed its revised natural gas rate sheets with the PSCW reflecting approximately $28 million of natural gas costs in excess of the benchmark set in its GCRM. WPS recovered these excess costs over a period of three months, beginning in April 2021.

PGL and NSG incurred approximately $131 million and $10 million, respectively, of natural gas costs in February 2021 in excess of the amounts included in their rates. These costs are being recovered over a period of 12 months, which started on April 1, 2021. PGL's and NSG's natural gas costs will be reviewed for prudency by the ICC as part of their annual natural gas cost reconciliation, which we expect to file with the ICC in April 2022. The ICC could order the refund of any costs determined to be imprudent as part of the reconciliation.

In February 2021, MERC incurred approximately $75 million of natural gas costs in excess of the benchmark set in its GCRM. In July 2021, MERC and four other Minnesota utilities filed a joint proposal with the MPUC to recover their respective excess natural gas costs. Under the proposal, MERC will recover $10 million of these costs through its annual natural gas true-up process over a period of 12 months, and the remaining $65 million over 27 months, both beginning in September 2021. In August 2021, the MPUC issued a written order approving this proposal; however, recovery of these costs and the issue of prudence has been referred to a contested-case proceeding. As a result of the proceeding, the MPUC could disallow recovery or order the refund of any costs determined to be imprudent. A decision regarding this review is expected in August 2022.

Natural gas costs incurred at MGU and UMERC in excess of the amount included in their respective rates were not significant.

### Coronavirus Disease – 2019

The global outbreak of COVID-19 was declared a pandemic by the World Health Organization and the CDC. COVID-19 has spread globally, including throughout the United States and, in turn, our service territories. Each of the states in which our regulated utilities operate declared a public health emergency and issued shelter-in-place orders in response to the COVID-19 pandemic. All of the shelter-in-place orders have since expired or been lifted. The PSCW, the ICC, the MPUC, and the MPSC all issued written orders requiring certain actions to ensure that essential utility services were available to customers in their respective jurisdictions. A summary of these orders is included below.

#### *Wisconsin*

In March 2020, the PSCW issued two orders in response to the COVID-19 pandemic. The first order required all public utilities in the state of Wisconsin, including WE, WPS, and WG, to temporarily suspend disconnections, the assessment of late fees, and deposit requirements for all customer classes. In addition, it required utilities to reconnect customers that were previously disconnected, offer deferred payment arrangements to all customers, and streamline the application process for customers applying for utility service.

In the second order issued in March 2020, the PSCW authorized Wisconsin utilities to defer expenditures and certain foregone revenues resulting from compliance with the first order, and expenditures as otherwise incurred to ensure safe, reliable, and affordable access to utility services during the declared public health emergency. The PSCW affirmed that this authorization for deferral included the incremental increase in uncollectible expense above what was being recovered in rates. As WE, WPS, and WG already have a cost recovery mechanism in place to recover uncollectible expense for residential customers, this deferral only impacted the recovery of uncollectible expense for their commercial and industrial customers. See Note 5, Credit Losses, for information regarding changes to our allowance for credit losses. On December 16, 2021, the PSCW approved a motion to end all COVID-related deferrals as of December 31, 2021. The total amount deferred at our Wisconsin utilities related to the COVID-19 pandemic was not significant as of December 31, 2021. The PSCW will review the recoverability and examine the prudency of any deferred amounts in future rate proceedings.

In June 2020, the PSCW issued a written order providing a timeline for the lifting of the temporary provisions required in the first March 2020 order. Utilities were allowed to disconnect commercial and industrial customers and require deposits for new service as of July 25, 2020 and July 31, 2020, respectively. After August 15, 2020, utilities were no longer required to offer deferred payment arrangements to all customers. Additionally, utilities were authorized to reinstate late fees except for the period between the first order and this supplemental order. Our Wisconsin utilities resumed charging late payment fees in late August 2020. Late payment fees were not charged on outstanding balances that were billed between the first order and late August 2020.

Subsequent to the June 2020 order, the PSCW extended the moratorium on disconnections of residential customers until November 1, 2020. In accordance with Wisconsin regulations, utilities are generally not allowed to disconnect residential customers for non-payment during the winter moratorium, which began on November 1, 2020 and ended on April 15, 2021. Utilities were allowed to continue assessing late payment fees during the winter moratorium. On April 5, 2021, the PSCW issued a written order indicating that it would not extend the moratorium on disconnections further; therefore, utilities could begin disconnecting residential customers for non-payment after April 15, 2021. Utilities are required to offer a deferred payment arrangement to low-income residential customers prior to disconnecting service. The order also allowed our Wisconsin utilities to resume charging late payment fees on the full balance of all outstanding arrears, regardless of the associated dates the service was provided, after April 15, 2021.

### *Illinois*

In March 2020, the ICC issued an order to all Illinois utilities, including PGL and NSG, requiring, among other things, a moratorium on disconnections of utility service and a suspension of late fees and penalties during the declared public health emergency. These provisions applied to all utility customer classes. Illinois utilities were also required to temporarily enact more flexible credit and collections procedures.

In June 2020, the ICC issued a written order approving a settlement agreement negotiated by Illinois utilities, ICC staff, and certain intervenors. The key terms of the settlement agreement included the following:

- The moratorium on disconnections and the suspension of late fees and penalties were extended until July 26, 2020.
- Customers disconnected after June 18, 2019 could be reconnected without being assessed a reconnection fee if reconnection was requested prior to August 25, 2020.
- Flexible deferred payment arrangements were required to be offered to residential and commercial and industrial customers for an extended period of time and with reduced down payment requirements.
- Deposit requirements were waived until August 25, 2020 for all residential customers, and were waived for an additional four months for residential customers that verbally expressed financial hardship.
- PGL and NSG were required to establish a bill payment assistance program with approximately $12.0 million and $1.2 million, respectively, available for eligible residential customers to provide relief from high arrearages.

In addition to the above, the settlement agreement approved in June 2020 authorized PGL and NSG to implement a SPC rider to recover incremental direct costs resulting from COVID-19, foregone late fees and reconnection charges, and the costs associated with their bill payment assistance programs incurred between March 1, 2021 and December 31, 2021. PGL and NSG began recovering costs under the SPC rider on October 1, 2020. Amounts deferred under the SPC rider are being recovered over 36 months and will be subject to review and reconciliation by the ICC. As of December 31, 2021, PGL's and NSG's regulatory assets related to the COVID-19 pandemic were $22.9 million, collectively.

Subsequent to the approval of the June 2020 settlement agreement, and at the request of the ICC, PGL and NSG agreed to extend the moratorium on disconnections for qualified low-income residential customers and residential customers expressing financial hardship through March 31, 2021. The annual winter moratorium in Illinois that generally prohibits PGL and NSG from disconnecting residential customers for non-payment began on December 1, 2020 and ended on March 31, 2021.

In March 2021, the ICC issued a written order approving a second settlement agreement negotiated by Illinois utilities, ICC staff, and certain intervenors. The key terms of this new settlement agreement were as follows:

- Utilities could start sending disconnection notices, on a staggered basis, as of April 1, 2021. Disconnections were done on a staggered schedule based on customer arrears and income levels (e.g. low income versus non-low income customers). Utilities were not allowed to disconnect customers for non-payment prior to June 30, 2021 if the customer's household income was below 300% of the federal poverty level and the customer was on a deferred payment plan.
- Utilities were required to continue offering flexible deferred payment arrangements with reduced down payment requirements to residential customers through June 30, 2021.
- Reconnection fees were waived for eligible low income customers through June 30, 2021. In addition, utilities will continue to exempt eligible low income customers from late payment fees and deposits.
- Each utility was required to continue, or renew, its bill payment assistance program through 2021. In addition to the $12.0 million PGL initially funded, PGL was required to fund an additional $6.0 million to its bill payment assistance program. No additional funding was required for NSG due to the amount still available for assistance from its initial funding. During April 2021, PGL's bill payment assistance program ended as all $18.0 million of funds were exhausted. NSG's bill payment assistance program ended in August 2021 when its funds were exhausted.
- Costs related to the provisions in the settlement agreement, including costs related to the bill payment assistance programs, were recoverable through the SPC rider.

### *Minnesota*

In May 2020, the MPUC issued a written order authorizing Minnesota utilities, including MERC, to track and defer COVID-19 related expenses and certain foregone revenues. The MPUC will review the recoverability and examine the prudency of any deferred amounts in future rate proceedings. As of December 31, 2021, amounts deferred at MERC related to the COVID-19 pandemic were not significant.

In June 2020, the MPUC verbally ordered Minnesota utilities to temporarily suspend disconnections and waive reconnection fees, service deposits, late fees, interest, and penalties for all residential customers. In addition, utilities were required to immediately reconnect residential customers that were previously disconnected. In August 2020, the MPUC issued a written order affirming these temporary provisions. Prior to the June 2020 verbal order issued by the MPUC, MERC had voluntarily taken actions to ensure its customers continued to receive utility services during the pandemic. These actions included, but were not limited to, temporarily suspending disconnections and waiving late payment fees for residential and small commercial and industrial customers that entered into payment plans.

In March 2021, the MPUC issued an order requiring Minnesota utilities to file a transition plan to resume collections and disconnections upon the earlier of an Executive Secretary finding the transition plan was complete, or 90 days following the expiration of Minnesota's declared peacetime emergency. MERC filed its transition plan in April 2021, and it was subsequently deemed complete by the Executive Secretary. In accordance with the transition plan, MERC resumed disconnections on August 2, 2021. MERC will not disconnect residential customers with past due balances if the customer has a pending application or has been deemed eligible for a financial assistance program. In addition, MERC will continue to offer flexible deferred payment arrangements to residential customers. For customers who enter, or are complying with, a payment arrangement, MERC will not impose any service deposits, down payments, interest, late payment fees, or reconnections fees through April 30, 2022.

### *Michigan*

In April 2020, the MPSC issued a written order requiring Michigan utilities, including MGU and UMERC, to put certain minimum protections in place during the COVID-19 pandemic. The minimum protections required by the order included the suspension of disconnections, late payment fees, deposits, and reconnection fees for certain vulnerable customers. In addition, utilities were required to extend access to and enhance the flexibility of payment plans to customers financially impacted by COVID-19.

As required in the MPSC order, MGU and UMERC filed responses with the MPSC in April 2020 affirming the actions being taken to protect customers. These actions provided protections to more customers than required by the MPSC order, and included suspending disconnections for all residential customers, waiving deposit requirements for new service, suspending the assessment of late fees for customers that entered into payment plans, and enhancing payment plan options for all customers.

The April 2020 MPSC order also authorized all Michigan utilities to defer, for potential future recovery, uncollectible expense incurred on or after March 24, 2020 that exceeded the amounts being recovered in rates. In July 2020, the MPSC issued an order denying Michigan utilities' ability to defer additional COVID-19 related expenses and certain foregone revenues. The MPSC indicated that utilities could still seek recovery of these costs and foregone revenues by filing additional information on the specifics of their request. MGU and UMERC filed comments with the MPSC in November 2020 indicating they had not experienced any material additional COVID-19 related expenses or foregone revenues, but will continue to monitor them and will notify the MPSC if they become material. At December 31, 2021, our Michigan utilities had not recorded any deferrals related to the COVID-19 pandemic.

In June 2021, MGU and UMERC worked with MPSC staff to develop a transition plan to resume collections and disconnections, while continuing to assist customers in managing their arrears balances. In accordance with the agreed upon transition plan, MGU and UMERC resumed pre-pandemic collection activities and residential service disconnections on August 2, 2021. Flexible deferred payment arrangements will continue to be available to customers.

## Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Wisconsin Gas LLC

### *2022 Rates*

In March 2021, WE, WPS, and WG filed an application with the PSCW for the approval of certain accounting treatments that will allow them to maintain their current electric, natural gas, and steam base rates through 2022 and forego filing a rate case for one year. In connection with the request, the three utilities also entered into an agreement, dated March 23, 2021, with various stakeholders. Pursuant to the terms of the agreement, the stakeholders fully supported the application. In September 2021, the PSCW issued written orders approving the application.

The final orders reflect the following:

- WE, WPS, and WG will amortize, in 2022, certain previously deferred balances to offset approximately half of their forecasted revenue deficiencies.
- WG will defer interest and depreciation expense associated with capital investments since its last rate case that otherwise would have been added to rate base in a 2022 test-year rate case.
- WE, WPS, and WG will defer any increases in tax expense due to changes in tax law that occur in 2021 and/or 2022.
- WE, WPS, and WG will maintain their earnings sharing mechanisms for 2022, with modification. The earnings sharing mechanisms were modified to authorize the utility to retain 100% of the first 15 basis points of earnings above its currently authorized ROE. This modification expires on December 31, 2022. The earnings sharing mechanisms otherwise remains as previously authorized.
- WE, WPS, and WG will file a full 2023-2024 test-year rate case no later than May 1, 2022.

### *2020 and 2021 Rates*

In March 2019, WE, WPS, and WG filed applications with the PSCW to increase their retail electric, natural gas, and steam rates, as applicable, effective January 1, 2020. In August 2019, all three utilities filed applications with the PSCW for approval of settlement agreements entered into with certain intervenors to resolve several outstanding issues in each utility's respective rate case. In December 2019, the PSCW issued written orders that approved the settlement agreements without material modification and addressed the remaining outstanding issues that were not included in the settlement agreements. The new rates were effective January 1, 2020. The final orders reflected the following:

| | WE | WPS | WG |
|---|---|---|---|
| 2020 Effective rate increase (decrease) | | | |
| Electric [1] [2] | $ 15.3 million / 0.5% | $ 15.8 million / 1.6% | N/A |
| Gas [3] | $ 10.4 million / 2.8% | $ 4.3 million / 1.4% | $ (1.5) million / (0.2)% |
| Steam | $ 1.9 million / 8.6% | N/A | N/A |
| ROE | 10.0% | 10.0% | 10.2% |
| Common equity component average on a financial basis | 52.5% | 52.5% | 52.5% |

(1) Amounts are net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impact. The WE and WPS rate orders reflected the majority of the unprotected deferred tax benefits from the Tax Legislation being amortized over two years. For WE, approximately $65 million of tax benefits were amortized in each of 2020 and 2021. For WPS, approximately $11 million of tax benefits were amortized in 2020 and approximately $39 million were amortized in 2021. The unprotected deferred tax benefits related to the unrecovered balances of certain of WE's retired plants and its SSR regulatory asset were used to reduce the related regulatory asset. Unprotected deferred tax benefits by their nature are eligible to be returned to customers in a manner and timeline determined to be appropriate by our regulators.

(2) The WPS rate order was net of $21 million of refunds related to its 2018 earnings sharing mechanism. These refunds were made to customers evenly over two years, with half returned in 2020 and the remainder returned in 2021.

(3) The WE amount includes certain deferred tax expense from the Tax Legislation, and the WPS and WG amounts are net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impact. The rate orders for all three gas utilities reflected all of the unprotected deferred tax expense and benefits from the Tax Legislation being amortized evenly over four years. For WE, approximately $5 million of previously deferred tax expense will be amortized each year. For WPS and WG, approximately $5 million and $3 million, respectively, of previously deferred tax benefits will be amortized each year. Unprotected deferred tax expense and benefits by their nature are eligible to be recovered from or returned to customers in a manner and timeline determined to be appropriate by our regulators.

In accordance with its rate order, WE filed an application with the PSCW in July 2020 requesting a financing order to securitize $100 million of Pleasant Prairie power plant's book value, plus the carrying costs accrued on the $100 million during the securitization process and the related financing fees. In November 2020, the PSCW issued a written order approving the application. The financing order also authorized WE to form a bankruptcy-remote special purpose entity, WEPCo Environmental Trust, for the sole purpose of issuing ETBs to recover the approved costs. In May 2021, WEPCo Environmental Trust issued $118.8 million of 1.578% ETBs due December 15, 2035. See Note 14, Long-Term Debt, for more information regarding the issuance of the ETBs. See Note 23, Variable Interest Entities, for more information regarding WEPCo Environmental Trust.

The WPS rate order allows WPS to collect the previously deferred revenue requirement for ReACT™ costs above the authorized $275.0 million level. The total cost of the ReACT™ project was $342 million. This regulatory asset is being collected from customers over eight years.

The PSCW approved all three Wisconsin utilities continuing to have an earnings sharing mechanism through 2021. The earnings sharing mechanism was modified from its previous structure to one that was consistent with other Wisconsin investor-owned utilities. Under this earnings sharing mechanism, if the utility earned above its authorized ROE: (i) the utility retained 100.0% of earnings for the first 25 basis points above the authorized ROE; (ii) 50.0% of the next 50 basis points were required to be refunded to customers; and (iii) 100.0% of any remaining excess earnings were required to be refunded to customers. In addition, the rate orders also required WE, WPS, and WG to maintain residential and small commercial electric and natural gas customer fixed charges at previously authorized rates and to maintain the status quo for WE's and WPS's electric market-based rate programs for large industrial customers through 2021.

## The Peoples Gas Light and Coke Company and North Shore Gas Company

### *Third-Party Transaction Fee Adjustment Rider*

In accordance with the Climate and Equitable Jobs Act that was signed into law in Illinois, effective September 15, 2021, utilities are prohibited from charging customers a fee when they elect to pay for service with a credit card. Utilities are now required to incur these expenses. On October 27, 2021, PGL and NSG filed requests with the ICC for approval of a TPTFA rider, which will allow for the recovery of these third-party transaction fee expenses that are now being incurred. The ICC approved the TPTFA rider for PGL on December 16, 2021, and it became effective on December 27, 2021. PGL began recovering costs under the rider on February 1, 2022. Amounts deferred under the rider will be recovered over a period of 12 months and will be subject to an annual reconciliation whereby costs will be reviewed by the ICC for accuracy and prudency. On January 3, 2022, NSG filed a motion with the ICC to withdraw its request for the TPTFA rider, which was subsequently accepted by the ICC. NSG recovers costs related to these third-party transaction fees through its recently established base rates.

### *North Shore Gas Company 2021 Rate Order*

In October 2020, NSG filed a request with the ICC to increase its natural gas rates. In September 2021, the ICC issued a written order authorizing a rate increase of $4.1 million (4.5%). The rate increase reflects a 9.67% ROE and a common equity component average of 51.58%. The natural gas rate increase is primarily driven by NSG's ongoing significant investment in its distribution system since its last rate review that resulted in revised base rates effective January 28, 2015. The new rates were effective September 15, 2021.

### *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 is in effect through 2023.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2021, PGL filed its 2020 reconciliation with the ICC, which, along with the 2019, 2018, 2017, and 2016 reconciliations, are still pending. In July 2019, the ICC approved a settlement of the 2015 reconciliation, which included a rate base reduction of $7.0 million and a $7.3 million refund to ratepayers.

As of December 31, 2021, there can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

## Minnesota Energy Resources Corporation

### *2018 Rate Order*

In October 2017, MERC initiated a rate proceeding with the MPUC. In December 2018, the MPUC issued a final written order for MERC. The order authorized a retail natural gas rate increase of $3.1 million (1.26%). The rates reflect a 9.7% ROE and a common equity component average of 50.9%. The final rates were implemented on July 1, 2019. The final approved rate increase was lower than the interim rates collected from customers during 2018 and through June 30, 2019. Therefore, MERC refunded $8.2 million to its customers during the second half of 2019.

The final order addressed the various impacts of the Tax Legislation, including the remeasurement of deferred tax balances. All of the impacts from the Tax Legislation have been included in base rates. The order also approved MERC's continued use of its decoupling mechanism for residential customers. Effective January 1, 2019, MERC's small commercial and industrial customers are no longer included in the decoupling mechanism.

## Michigan Gas Utilities Corporation

### *2021 Rate Order*

In February 2020, MGU provided notification to the MPSC of its intent to file an application requesting an increase to MGU's natural gas rates to be effective January 1, 2021. However, MGU decided that it would delay its filing of the rate case as a result of the COVID-19 pandemic.

In May 2020, MGU filed an application with the MPSC requesting approval to defer $5.0 million of depreciation and interest expense during 2021 related to capital investments made by MGU since its last rate case. In July 2020, the MPSC issued a written order approving MGU's request. The deferral of these costs helped to mitigate the impacts from delaying the filing of the rate case.

In March 2021, MGU filed its request with the MPSC to increase its natural gas rates. In July 2021, MGU filed with the MPSC, a settlement agreement it reached with certain intervenors, which the MPSC approved in a written order in September 2021. The order authorizes a rate increase of $9.3 million (6.35%) and reflects a 9.85% ROE and a common equity component average of 51.5%. The natural gas rate increase was primarily driven by MGU's significant investment in capital infrastructure since its last rate review that resulted in revised base rates effective January 1, 2016. The order also allows MGU to implement a rider for its Main Replacement Program that will support recovery of planned capital investment related to pipeline replacements to maintain system safety and reliability between 2023 and 2027, without having to file a rate case. We expect approximately $31.7 million of costs to be recovered through this rider. All costs recovered through the rider are subject to a prudence review by the MPSC. The new rates became effective January 1, 2022.

## NOTE 27—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Non-service components of net periodic benefit costs | **$ 72.2** | $ 41.2 | $ 36.2 |
| AFUDC – Equity | **18.0** | 20.9 | 14.4 |
| Gains from investments held in rabbi trust | **18.6** | 12.7 | 21.2 |
| Earnings from equity method investments [1] | **19.9** | 2.4 | 3.5 |
| Other, net | **4.5** | 2.3 | 26.9 |
| **Other income, net** | **$ 133.2** | $ 79.5 | $ 102.2 |

[1] Amount does 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

### Simplifying the Accounting for Income Taxes

In December 2019, the FASB issued ASU 2019-12, Simplifying the Accounting for Income Taxes. The new standard removes certain exceptions for performing intraperiod allocation and calculating income taxes in interim periods and also adds guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. The guidance was effective for annual and interim periods beginning after December 15, 2020. The adoption of ASU 2019-12, effective January 1, 2021, did not have a significant impact on our financial statements and related disclosures.

### Reference Rate Reform

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting, which provides optional expedients and exceptions for applying GAAP to contracts, hedging relationships, and other transactions affected by reference rate reform if certain criteria are met. The amendments apply only to contracts, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued because of reference rate reform. The amendments are effective for all entities as of March 12, 2020 through December 31, 2022. We are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

## Government Assistance

In November 2021, the FASB issued ASU No. 2021-10, Government Assistance (Topic 832). The amendments in this update increase the transparency surrounding government assistance by requiring disclosure of 1) the types of assistance received, 2) an entity's accounting for the assistance, and 3) the effect of the assistance on the entity's financial statements. The update is effective for annual periods beginning after December 15, 2021. We plan to adopt this pronouncement for our fiscal year ending on December 31, 2022, and we 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, 2021.

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 2021 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
On February 21, 2022, WEC Energy Group and Scott J. Lauber, the Company's President and Chief Executive Officer, entered into a letter agreement, which was approved by the Compensation Committee. Pursuant to the terms of this agreement, WEC Energy Group will credit an annual contribution of $300,000 to a nonqualified account beginning February 21, 2022. So long as Mr. Lauber remains employed by WEC Energy Group, an additional $300,000 will be credited annually on February 1, until a maximum of 10 contributions have been made. In addition, the account will be credited with interest at a rate of 5.0% annually, which is equivalent to the interest crediting rate under WEC Energy Group's cash balance pension plan. The account vests upon the sixth contribution at which time Mr. Lauber will be 61, or upon Mr. Lauber's death or disability.

## 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 2023 – 2022 Director Nominees for Election," "Delinquent Section 16(a) Reports," "Annual Meeting Attendance and Voting Information – Stockholder Nominees and Proposals," and "Governance – Board Committees – Audit and Oversight" in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Shareholders to be held May 5, 2022 (the "2022 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 2022 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 2022 Annual Meeting Proxy Statement.

### Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans as of December 31, 2021:

| 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 | 3,111,907 | $ 69.84 | 9,008,198 (1) |
| Equity Compensation Plans Not Approved by Security Holders | N/A | N/A | N/A |
| **Total** | 3,111,907 | $ 69.84 | 9,008,198 |

(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 2023 – Board Composition – Independence," and "Governance – Board Committees" in the 2022 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 audit and oversight committee under "Independent Auditors' Fees and Services" in the 2022 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, Inc., 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, Inc., as amended. (Exhibit 3.1 to WEC Energy Group's 06/29/15 Form 8-K.) |
| | 3.3* | Bylaws of WEC Energy Group, Inc., as amended to April 16, 2020. (Exhibit 3.1 to WEC Energy Group's 04/20/20 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, Inc. (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 12/31/2019 Form 10-K.) |
| | 4.3* | Replacement Capital Covenant, dated May 11, 2007, by Wisconsin Energy Corporation for the benefit of certain debtholders named therein. (Exhibit 4.2 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.) |
| | 4.4* | Amendment to Replacement Capital Covenant, dated as of June 29, 2015. (Exhibit 4.1 to WEC Energy Group's 06/29/15 Form 8-K.) |
| | ***Indentures and Securities Resolutions:*** | |
| | 4.5* | Indenture for Debt Securities of Wisconsin Electric Power Company (the "Wisconsin Electric Indenture"), dated December 1, 1995. (Exhibit (4)-1 under File No. 1-1245, WE's 12/31/95 Form 10-K.) |
| | 4.6* | Securities Resolution No. 1 of Wisconsin Electric under the Wisconsin Electric Indenture, dated December 5, 1995. (Exhibit (4)-2 under File No. 1-1245, WE's 12/31/95 Form 10-K.) |
| | 4.7* | Securities Resolution No. 3 of Wisconsin Electric under the Wisconsin Electric Indenture, dated May 27, 1998. (Exhibit (4)-1 under File No. 1-1245, WE’s 06/30/98 Form 10-Q.) |
| | 4.8* | Securities Resolution No. 5 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-101054), filed May 6, 2003.) |
| | 4.9* | Securities Resolution No. 7 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 2, 2006. (Exhibit 4.1 under File No. 1-1245, WE's 11/02/06 Form 8-K.) |
| | 4.10* | Securities Resolution No. 12 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 5, 2012. (Exhibit 4.1 under File No. 1-1245, WE's 12/05/12 Form 8-K.) |
| | 4.11* | Securities Resolution No. 14 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 12, 2014. (Exhibit 4.1 under File No. 1-1245, WE's 05/12/14 Form 8-K.) |
| | 4.12* | Securities Resolution No. 15 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 14, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 05/14/15 Form 8-K.) |
| | 4.13* | Securities Resolution No. 16 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 13, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 11/13/15 Form 8-K.) |
| | 4.14* | Securities Resolution No. 17 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of October 1, 2018. (Exhibit 4.1 under File No. 1-1245, WE's 10/01/18 Form 8-K.) |
| | 4.15* | Securities Resolution No. 18 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 3, 2019. (Exhibit 4.1 under File No. 1-1245, WE's 12/3/19 Form 8-K.) |
| | 4.16* | Securities Resolution No. 19 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of June 8, 2021 (Exhibit 4.1 under File No. 1-1245, WE's 6/15/21 Form 8-K.) |
| | 4.17* | 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.) |
| | 4.18* | 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 | |
|---|---|---|
| | 4.19* | Securities Resolution No. 5 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, effective as of May 8, 2007. (Exhibit 4.1 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.) |
| | 4.20* | Securities Resolution No. 6 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, effective as of June 4, 2015. (Exhibit 4.1 to Wisconsin Energy Corporation's 06/04/15 Form 8-K.) |
| | 4.21* | Securities Resolution No. 9 of WEC Energy Group under the Wisconsin Energy Indenture, effective as of September 14, 2020. (Exhibit 4.1 to WEC Energy Group's 09/14/20 Form 8-K.) |
| | 4.22* | 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.) |
| | 4.23* | Securities Resolution No. 11 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of March 16, 2021 (Exhibit 4.1 to WEC Energy Group's 3/19/21 Form 8-K.) |
| | 4.24* | 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.) |
| | 4.25* | Indenture, dated as of December 1, 1998, between Wisconsin Public Service Corporation ("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). |
| | 4.26* | 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). |
| | 4.27* | 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). |
| | 4.28* | 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). |
| | 4.29* | 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). |
| | 4.30* | 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). |
| | 4.31* | 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). |
| | | Certain agreements and instruments with respect to unregistered long-term debt not exceeding 10 percent of the total assets of the Registrant and its subsidiaries on a consolidated basis have been omitted as permitted by related instructions. 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* | 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.)** |
| | 10.5* | 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.)** |

| Number | Exhibit |
|---|---|
| 10.6* | WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2018.** |
| 10.7* | WEC Energy Group Supplemental Long Term Disability Plan, Amended and Restated Effective as of January 1, 2017.** |
| 10.8* | WEC Energy Group Short-Term Performance Plan, Amended and Restated Effective as of January 1, 2019.** |
| 10.9* | 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.)** |
| 10.10* | Letter Agreement by and between WEC Energy Group, Inc. and Xia Liu, dated March 24, 2020. (Exhibit 10.2 to WEC Energy Group's 03/31/20 Form 8-K.)** |
| 10.11* | Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of October 21, 2020. (Exhibit 10.1 to WEC Energy Group's 10/21/2020 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 Wisconsin Energy Corporation and Joseph Kevin Fletcher, dated as of August 17, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/11 Form 10-Q.)** |
| 10.14* | Letter Agreement by and between WEC Energy Group, Inc. and Margaret C. Kelsey, dated as of July 19, 2017. (Exhibit 10.1 to WEC Energy Group's 09/30/17 Form 10-Q.)** |
| 10.15* | Letter Agreement by and between WEC Energy Group, Inc. and Scott J. Lauber, dated March 31, 2020. (Exhibit 10.1 to WEC Energy Group's 03/31/20 Form 8.K.)** |
| 10.16 | Retention Agreement by and between WEC Energy Group and Scott J. Lauber, dated February 21, 2022.** |
| 10.17.1* | 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.)** |
| 10.17.2* | 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.)** |
| 10.18* | Terms and Conditions Governing Non-Qualified Stock Option Award under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q.)** |
| 10.19* | 2016 WEC Energy Group Terms and Conditions Governing Director Restricted Stock Awards under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.24 to WEC Energy Group's 12/31/15 Form 10-K.)** |
| 10.20* | Director Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 12/01/16 Form 8-K.)** |
| 10.21* | WEC Energy Group Performance Unit Plan, amended and restated effective as of January 1, 2017. (Exhibit 10.1 to WEC Energy Group's 12/01/16 Form 8-K.)** |
| 10.22* | 2016 WEC Energy Group Restricted Stock Award Terms and Conditions governing awards under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.27 to WEC Energy Group's 12/31/15 Form 10-K.)** |
| 10.23* | Wisconsin Energy Corporation Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the WEC Energy Group Omnibus Stock Incentive Plan, approved December 4, 2014. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/04/14 Form 8-K.)** |

| Number | | Exhibit |
|---|---|---|
| | 10.24* | 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.)** |
| | 10.25* | 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 6/30/21 Form 10-Q.)** |
| | 10.26* | Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan (Exhibit 10.3 to WEC Energy Group's 6/30/21 Form 10-Q.)** |
| | 10.27* | Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan (1 Year Vesting) (Exhibit 10.4 to WEC Energy Group's 6/30/21 Form 10-Q.)** |
| | 10.28* | Director Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan (Exhibit 10.5 to WEC Energy Group's 6/30/21 Form 10-Q.)** |
| | 10.29* | Port Washington I Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to WE's 06/30/03 Form 10-Q (File No. 001-01245).) |
| | 10.30* | Port Washington II Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to WE's 06/30/03 Form 10-Q (File No. 001-01245).) |
| | 10.31* | Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.) |
| | 10.32* | Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.) |
| | 10.33* | Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q.) |
| | 10.34* | Letter Agreement between Wisconsin Electric Power Company 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.) |
| | 10.35* | 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.)** |
| | 10.36* | 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.)** |
| **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. |
| **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. |

| Number | Exhibit | |
|---|---|---|
| **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. |
| **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**<br>***(in millions)*** | **2021** | **2020** | **2019** |
|---|---|---|---|
| Operating expenses | **$ 12.0** | $ 5.3 | $ 4.7 |
| Equity earnings of subsidiaries | **1,367.0** | 1,283.8 | 1,210.5 |
| Other income, net | **1.7** | 1.3 | 6.3 |
| Interest expense | **70.2** | 96.9 | 122.3 |
| Loss on debt extinguishment | **23.1** | 38.4 | — |
| Income before income taxes | **1,263.4** | 1,144.5 | 1,089.8 |
| Income tax benefit | **36.9** | 55.4 | 44.2 |
| **Net income attributed to common shareholders** | **$ 1,300.3** | $ 1,199.9 | $ 1,134.0 |

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<br>*(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **Net income attributed to common shareholders** | **$ 1,300.3** | $ 1,199.9 | $ 1,134.0 |
| | | | |
| **Other comprehensive income (loss), net of tax** | | | |
| **Derivatives accounted for as cash flow hedges** | | | |
| Net derivative gain (loss), net of tax expense (benefit) of $0.2, $(1.6), and $(1.3), respectively | **0.6** | (4.3) | (3.5) |
| Reclassification of realized net derivative (gain) loss to net income, net of tax | **0.9** | 1.5 | (0.8) |
| **Cash flow hedges, net** | **1.5** | (2.8) | (4.3) |
| | | | |
| **Defined benefit plans** | | | |
| Pension and OPEB adjustments arising during the period, net of tax | **0.4** | (0.4) | 0.4 |
| Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax | **0.3** | 0.3 | 0.2 |
| **Defined benefit plans, net** | **0.7** | (0.1) | 0.6 |
| | | | |
| **Other comprehensive income from subsidiaries, net of tax** | **1.4** | 0.2 | 2.2 |
| | | | |
| **Other comprehensive income (loss), net of tax** | **3.6** | (2.7) | (1.5) |
| | | | |
| **Comprehensive income attributed to common shareholders** | **$ 1,303.9** | $ 1,197.2 | $ 1,132.5 |

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

## C. BALANCE SHEETS

| At December 31<br>*(in millions)* | 2021 | 2020 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 0.5** | $ 4.0 |
| Accounts receivable from related parties | **0.6** | 0.7 |
| Notes receivable from related parties | **29.0** | 110.8 |
| Prepaid taxes | **56.5** | 54.4 |
| Other | **0.1** | 0.1 |
| **Current assets** | **86.7** | 170.0 |
| | | |
| **Long-term assets** | | |
| Investments in subsidiaries | **15,365.4** | 14,248.3 |
| Other | **21.8** | 15.7 |
| **Long-term assets** | **15,387.2** | 14,264.0 |
| **Total assets** | **$ 15,473.9** | $ 14,434.0 |
| | | |
| **Liabilities and Equity** | | |
| **Current liabilities** | | |
| Short-term debt | **$ 736.1** | $ 820.4 |
| Accounts payable to related parties | **5.5** | 31.7 |
| Notes payable to related parties | **220.4** | 303.0 |
| Other | **21.5** | 19.6 |
| **Current liabilities** | **983.5** | 1,174.7 |
| | | |
| **Long-term liabilities** | | |
| Long-term debt | **3,549.8** | 2,754.8 |
| Other | **27.4** | 34.8 |
| **Long-term liabilities** | **3,577.2** | 2,789.6 |
| | | |
| Common shareholders' equity | **10,913.2** | 10,469.7 |
| **Total liabilities and equity** | **$ 15,473.9** | $ 14,434.0 |

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<br>*(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| **Operating activities** | | | |
| Net income attributed to common shareholders | **$ 1,300.3** | $ 1,199.9 | $ 1,134.0 |
| Reconciliation to cash provided by operating activities | | | |
| Equity income in subsidiaries, net of distributions | **(571.3)** | (385.7) | (475.2) |
| Deferred income taxes, net | **(1.9)** | 12.7 | 9.1 |
| Loss on debt extinguishment | **23.1** | 38.4 | — |
| Change in – | | | |
| Accounts receivable from related parties | **0.1** | — | 3.3 |
| Prepaid taxes | **(2.1)** | (7.9) | (46.5) |
| Accounts payable to related parties | **(26.2)** | 29.2 | (5.2) |
| Other current liabilities | **8.6** | (2.4) | 1.5 |
| Other, net | **(2.5)** | 9.6 | 7.0 |
| **Net cash provided by operating activities** | **728.1** | 893.8 | 628.0 |
| | | | |
| **Investing activities** | | | |
| Capital contributions to subsidiaries | **(734.0)** | (1,026.1) | (602.3) |
| Return of capital from subsidiaries | **196.1** | 602.8 | 337.3 |
| Short-term notes receivable from related parties, net | **81.8** | (88.3) | 48.5 |
| Redemption of long-term notes receivable from UMERC | **—** | — | 150.0 |
| Other, net | **(1.1)** | 3.7 | (0.6) |
| **Net cash used in investing activities** | **(457.2)** | (507.9) | (67.1) |
| | | | |
| **Financing activities** | | | |
| Exercise of stock options | **15.7** | 43.8 | 67.0 |
| Purchase of common stock | **(33.1)** | (99.2) | (140.1) |
| Dividends paid on common stock | **(854.8)** | (798.0) | (744.5) |
| Issuance of long-term debt | **1,100.0** | 1,650.0 | 350.0 |
| Retirement of long-term debt | **(300.0)** | (1,430.0) | — |
| Issuance of short-term loan | **—** | 340.0 | — |
| Repayment of short-term loan | **(340.0)** | — | — |
| Change in other short-term debt | **255.7** | 145.7 | (213.7) |
| Short-term notes payable to related parties, net | **(82.6)** | (186.3) | 90.4 |
| Payments for debt extinguishment and issuance costs | **(33.9)** | (47.3) | (0.8) |
| Other, net | **(1.4)** | (1.1) | (1.5) |
| **Net cash used in financing activities** | **(274.4)** | (382.4) | (593.2) |
| | | | |
| **Net change in cash and cash equivalents** | **(3.5)** | 3.5 | (32.3) |
| Cash and cash equivalents at beginning of year | **4.0** | 0.5 | 32.8 |
| **Cash and cash equivalents at end of year** | **$ 0.5** | $ 4.0 | $ 0.5 |

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)* | **2021** | **2020** | **2019** |
|---|---|---|---|
| WE | **$ 360.0** | $ 395.0 | $ 360.0 |
| We Power | **217.9** | 240.9 | 192.5 |
| ATC Holding [(1)] | **106.4** | 112.6 | 87.4 |
| WECI [(2)] | **46.4** | 33.6 | 25.4 |
| Bluewater | **35.0** | — | — |
| WG | **30.0** | 70.0 | 60.0 |
| UMERC | **—** | 46.0 | 10.0 |
| **Total** | **$ 795.7** | $ 898.1 | $ 735.3 |

(1) We also received amounts classified as return of capital of $32.0 million, $19.6 million, and $220.6 million from ATC Holding during the years ended December 31, 2021, 2020, and 2019, respectively.

(2) We also received amounts classified as return of capital of $164.1 million, $583.2 million, and $116.7 million from WECI during the years ended December 31, 2021, 2020, and 2019, respectively.

### NOTE 3—LONG-TERM DEBT

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2021:

| *(in millions)* | |
|---|---|
| 2022 | $ — |
| 2023 | 700.0 |
| 2024 | 600.0 |
| 2025 | 120.0 |
| 2026 | — |
| Thereafter | 2,150.0 |
| **Total** | $ 3,570.0 |

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:

| | 2021 | | 2020 | |
|---|---|---|---|---|
| *(in millions)* | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-term debt, including current portion | **$ 3,549.8** | **$ 3,546.9** | $ 2,754.8 | $ 2,836.9 |

The fair value of our long-term debt is categorized within Level 2 of the fair value hierarchy.

## NOTE 5—GUARANTEES

The following table shows our outstanding guarantees on behalf of our subsidiaries:

| | Total Amounts Committed at December 31, 2021 | Expiration | | |
|---|---|---|---|---|
| *(in millions)* | | Less Than 1 Year | 1 to 3 Years | Over 3 Years |
| Guarantees supporting business operations (1) | **$ 888.4** | $ 813.7 | $ 1.2 | $ 73.5 |
| Standby letters of credit (2) | **27.8** | 2.5 | — | 25.3 |
| Surety bonds (3) | **12.8** | 12.8 | — | — |
| Other guarantees (4) | **9.4** | — | — | 9.4 |
| **Total guarantees** | **$ 938.4** | $ 829.0 | $ 1.2 | $ 108.2 |

(1) Consists of $6.2 million, $9.7 million, and $872.5 million of guarantees to support the business operations of UMERC, Bluewater, and WECI, respectively.

(2) At our request, 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 workers compensation self-insurance programs and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Consists of $9.4 million related to workers compensation coverage for which a liability was recorded on our balance sheets.

## NOTE 6—SUPPLEMENTAL CASH FLOW INFORMATION

| *(in millions)* | 2021 | 2020 | 2019 |
|---|---|---|---|
| Cash paid for interest | **$ 70.2** | $ 98.5 | $ 117.7 |
| Cash received for income taxes, net | **(27.9)** | (61.5) | (4.9) |

## 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)* | 2021 | 2020 |
|---|---|---|
| UMERC | **$ 22.0** | $ 30.7 |
| Bluewater | **7.0** | — |
| Integrys | **—** | 68.1 |
| Wispark | **—** | 12.0 |
| **Total** | **$ 29.0** | $ 110.8 |

## 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)* | 2021 | 2020 |
|---|---|---|
| WBS | **$ 107.7** | $ 149.0 |
| WECC | **107.4** | 110.0 |
| Integrys | **5.3** | — |
| Bluewater | **—** | 44.0 |
| **Total** | **$ 220.4** | $ 303.0 |

## 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) | **Sale of Business** | **Balance at End of Period** |
|---|---|---|---|---|---|---|
| **December 31, 2021** | **$ 220.1** | **$ 107.4** | **$ (44.8)** | **$ (84.4)** | **$ —** | **$ 198.3** |
| December 31, 2020 | 140.0 | 102.8 | 55.3 | (77.9) | (0.1) | 220.1 |
| December 31, 2019 | 149.2 | 85.8 | 11.4 | (106.4) | — | 140.0 |

(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 24, 2022 | 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<br>Scott J. Lauber, President and Chief Executive Officer, and Director --<br>Principal Executive Officer | February 24, 2022 |
| /s/ XIA LIU<br>Xia Liu, Executive Vice President and Chief Financial Officer --<br>Principal Financial Officer | February 24, 2022 |
| /s/ WILLIAM J. GUC<br>William J. Guc, Vice President and Controller --<br>Principal Accounting Officer | February 24, 2022 |
| /s/ GALE E. KLAPPA<br>Gale E. Klappa, Executive Chairman and Director | February 24, 2022 |
| /s/ CURT S. CULVER<br>Curt S. Culver, Director | February 24, 2022 |
| /s/ DANNY L. CUNNINGHAM<br>Danny L. Cunningham, Director | February 24, 2022 |
| /s/ WILLIAM M. FARROW III<br>William M. Farrow III, Director | February 24, 2022 |
| /s/ CRISTINA A. GARCIA-THOMAS<br>Cristina A. Garcia-Thomas, Director | February 24, 2022 |
| /s/ MARIA C. GREEN<br>Maria C. Green, Director | February 24, 2022 |
| /s/ THOMAS K. LANE<br>Thomas K. Lane, Director | February 24, 2022 |
| /s/ ULICE PAYNE, JR.<br>Ulice Payne, Jr., Director | February 24, 2022 |
| /s/ MARY ELLEN STANEK<br>Mary Ellen Stanek, Director | February 24, 2022 |
| /s/ GLEN E. TELLOCK<br>Glen E. Tellock, Director | February 24, 2022 |

**Exhibit 10.16**

[WEC Energy Group Letterhead]

February 21, 2022

Scott,

The Company wishes to encourage your continued employment through the date of your retirement to ensure continuity of CEO leadership and to provide sufficient time for longer term succession planning to develop the future leadership team of the organization.

To retain your employment with the Company, the Compensation Committee has approved this retention agreement effective February 21, 2022. Under the agreement, the Company will credit an annual contribution of $300,000 to a notional account beginning with the effective date of the agreement. So long as you are employed with the Company, an additional $300,000 will be credited annually on February 1st until a maximum of ten (10) contributions have been made. The account will be credited with annual interest at the rate of 5%. The account balance will vest on February 1, 2027 when the 6th contribution to the account has been credited. The account will be distributed as soon as administratively possible after your separation of service in a form elected by you and will be immediately vested in the event of your death or disability. The beneficiaries of this retention agreement shall be the same as those designated for your Executive Deferred Compensation Plan benefit. Administration of this benefit will comply with Section 409A of the Internal Revenue Code.

Scott, I look forward to continuing to work together as you lead WEC.

Sincerely,

/s/ Gale E. Klappa

Gale E. Klappa
Executive Chairman

Accepted:

| /s/ Scott J. Lauber | 02/21/2022 |
| --- | --- |
| Scott J. Lauber | Date |

**Exhibit 21.1**

# WEC ENERGY GROUP, INC.
## SUBSIDIARIES AS OF DECEMBER 31, 2021

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, 2021:

| Subsidiary * | State of Incorporation or Organization | Percent Ownership |
|---|---|---|
| **ATC Holding LLC** | Wisconsin | 100% |
| American Transmission Company LLC | Wisconsin | 60.31% |
| 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% |
| Peoples Energy Ventures, LLC | Delaware | 100% |
| The Peoples Gas Light and Coke Company | Illinois | 100% |
| Wisconsin Public Service Corporation | Wisconsin | 100% |
| Wisconsin River Power Company | Wisconsin | 50% |
| Wisconsin Valley Improvement Company | Wisconsin | 27% |
| WPS Power Development, LLC | Wisconsin | 100% |
| WPS Visions, Inc. | Wisconsin | 100% |
| **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% |
| Jayhawk Wind, LLC | Delaware | 90% |
| Tatanka Ridge Wind, LLC | Delaware | 85% |
| 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 | 80% |
| Upstream Wind Energy Holdings LLC | Delaware | 90% |
| **WEC Investments, LLC** | Delaware | 100% |
| **Wisconsin Electric Power Company** | Wisconsin | 100% |
| **Wisconsin Energy Capital Corporation** | Wisconsin | 100% |
| **Wisconsin Gas LLC** | Wisconsin | 100% |
| **Wispark LLC** | Wisconsin | 100% |
| **Wisvest 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, 2021. 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. 333-260807 and 333-249542 on Form S-3 and Registration Statement Nos. 333-213589, 333-161151 and 333-177572 on Form S-8 of our reports dated February 24, 2022, relating to the consolidated financial statements and financial statement schedules of WEC Energy Group, Inc. and the effectiveness of the Company'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, 2021.

**/s/DELOITTE & TOUCHE LLP**

Milwaukee, Wisconsin
February 24, 2022

**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 24, 2022

/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 24, 2022

/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, 2021, as filed with the Securities and Exchange Commission on February 24, 2022 (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 24, 2022

**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, 2021, as filed with the Securities and Exchange Commission on February 24, 2022 (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 24, 2022